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Bachelor's Degree in Energy Engineering

2018-2019

Bachelor Thesis

"Electricity system planning with a high penetration of renewable energies"

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Leganés, Jun 2019

ABSTRACT

Due to society's increasingly concern about environmental sustainability, many agreements have been signed in the European Union in the past few years to establish medium- and long-term energy frameworks that point out the main energy transition politics that will be taken by all members. Inspired on these politics, this study tries to find which would be the most efficient thermal power generation park needed to ensure the correct and safe operation of the Spanish Peninsula electricity system in a situation where, by 2030, 80 % of total energy production came from renewable energy sources.

To perform this study, demand and generation values of two different years are scaled to 2030. Three scenarios are considered regarding the conventional technologies that constitute the thermal power generation park: nuclear, coal and combined cycle as conventional technologies; coal and combined cycle as conventional technologies; and only combined cycle as conventional technology. In each scenario, an optimization process performed with *linprog* Matlab function is carried out to find which is the most economically optimum distribution of installed capacities and energy generations shares.

Results show that, if 80 % of energy generation comes from renewable energy sources by 2030, total installed capacity of the system will increase significantly due to low capacity factors of renewable technologies, causing a considerably large energy spillage because of the unprogrammable nature of these technologies. In a scenario where nuclear, coal and combined cycle technologies constitute the thermal generation park, it is proven that nuclear technology operating as baseload units and combined cycle technology as peaking units is the economically optimum situation. Because of the huge variations of nuclear technology costs that are found depending on the source checked, its investment cost considered for the study is increased until this technology becomes economically suboptimal to operate. The investment cost that makes it happen is found to be within the range of investment costs of nuclear technologies provided in several sources. In a scenario where combined cycle is the only conventional technology constituting the thermal generation mix is possible to obtain an hourly price of electricity, so the remuneration perceived by generators can be compared with total costs of the system. This comparison shows that that costs of the system double the remuneration perceived by all generators, which leads to considerably high payments by capacity mechanisms.

ACKNOWLEDGEMENTS

I would like to express my special thanks of gratitude to my bachelor thesis director, Julio García Usaola, for giving me the opportunity to do this project, from who I have learnt many things. I would also like to thank Asier Moltó Llovet, my professor of Energy demand management, for opening my eyes and making me realize what I want to dedicate my professional life to.

Secondly, I would like to thank my parents and sister for making me the person I am now, giving me the strength needed at any moment, and supporting me in all decisions I have taken.

GENERAL INDEX

TABLE INDEX

FIGURE INDEX

1. INTRODUCTION

1.1 Project motivation

According to the World Health Organization, ambient air pollution accounts for an estimated 4.2 million deaths per year due to stroke, heart disease, lung cancer and chronic respiratory diseases. Around 91% of the world's population lives in places where air quality levels exceed WHO limits. Policies and investments supporting cleaner transport, energy-efficient housing, power generation, industry and better municipal waste management can effectively reduce key sources of ambient air pollution. One of the most direct ways of reducing greenhouse gases emissions is transforming the current electric system by significantly increase the renewable energy generation. [1]

Developed countries, and especially European countries, are being more and more concerned every year about environmental sustainability and how to leave a clean and eco-friendly planet for future generations. These have led to the signing of many international agreements, being the last one, the Paris agreement, the one that has really represented a turning point in the international environmental agenda. This agreement is a bridge between today's policies and climate-neutrality before the end of the century. It sets out a global action plan to put the world on track to avoid dangerous climate change by limiting global warming to well below 2ºC and pursuing efforts to limit it to 1ºC.

In the context of these agreements, the European Union has set up two climate and energy frameworks, one for 2030 and another for 2050. Key targets for 2030 are:

- At least 40 % cuts on greenhouse gas emissions (from 1990 levels).
- At least 32 % share for renewable energy.
- At least 32.5 % improvement in energy efficiency.

The 2050 framework implies a long-term strategy in which it is shown how Europe can lead the way to climate neutrality ensuring social fairness for a just transition [2]. The effort needed to decarbonize the economy is huge, so it has led to a debate about an the so-called "Energy Transition", setting it in the center of the political agenda.

The changes required have many implications in the whole economy, but they will mainly affect the industrial sector (in which energy is a basic production factor), the transportation sector, the residential sector, and the electricity generation [3]. For this reason, they are starting to occupy an important place in the political agenda, being a high penetration of renewable energies generation one of the main measures announced.

This project will try to elucidate which is the most efficient thermal power generation park needed to ensure the correct and safe operation of the Spanish Peninsula electricity system with a high penetration of renewable energy production.

1.2 Objective

Inspired on the objectives established by the EU, but taken them to a more extreme situation, **a case of an electricity system with an 80% of renewable energies production for the Spanish peninsula demand in 2030 has been studied**. To carry out the study, some assumptions has been used:

1) The energy demand of Spain will grow 0.9% each year.
2) A minimum of 5 GWh of energy produced by conventional technologies is required in order to assure the energy demand.
3) There will only be considered nuclear, coal and combined cycle technologies for thermal generation.
4) There will only be considered wind, photovoltaic, solar thermal, and other renewables[1] as renewable energies.
5) Hydraulic and other renewables generations will be considered constant throughout the years.
6) There is no limit for installed capacity.

This study will try to elucidate which is the optimal thermal generation park needed to cover 20 % of energy production that renewable energies will not cover, and the installed

[1] Other Renewables includes Biomass, Biogas, Geothermal, and Marine hydraulic.

capacity of different renewable technologies needed to cover the target of 80 % of renewable energy production. Three different scenarios have been considered for this purpose: one where nuclear, combined cycle and coal are the three conventional technologies considered; another one where costs of nuclear technology are too high for it to be economically optimum to enter in the generation mix; and a last one where combined cycle in the only conventional technology operating.

1.3 Structure

The study is structured into four parts: a first part where data from base scenarios is processed, scale to 2030, and operated to make renewable technologies produce 80 % of total energy generation; a second part where the thermal generation park is optimized to cover the resulting thermal demand for each of the two first study cases; a third part where average costs of electricity for 2030 and base scenarios are calculated and compared, employing LCOEs, for the two first study cases; and a fourth part where, as stated in study case 3, only combined cycle technology is considered as conventional technology covering the thermal demand, which opens up the opportunity to go a step further regarding the costs of the system.

2. SPANISH ELECTRICITY SYSTEM

2.1 Characteristics of the system

According to the official definition, electricity supply consists on the delivery of it through transmission and distribution networks by means of an economic compensation in quality and consistency conditions demanded. [4]

The electricity supply is a service of general interest, since economic and human activities could not be carried out without it. For that reason, a sufficient capacity of generation, transport, and distribution must be guaranteed.

The management of the electricity supply is made through some activities carried out under a natural monopoly regime and others under a market regime. Energy transmission and distribution duties are natural monopolies. Incomes of the implicated agents are regulated by law and the convenient investments planned must be made by the regulatory organism, MINETUR. Coordination activities are not subjected to competition either; however, generation and commercialization activities are. Generators compete in the wholesale market, while retailers do so in the retail market. By 2017, there were 83 generators and 330 retailers in the Spanish Peninsula system [5]. The market operator for the whole peninsula system is OMIE, and the market supervisor is the CNMC, which is in charge of the defense and promotion of competition in Spain.

The Spanish electricity system is characterized by a low international connection level, a rate deficit, and a high weight of hydrocarbons in energy production.

2.2 Activities

The main activities implicated in the electricity supply are generation, transmission, distribution, commercialization, and electricity demand.

2.2.1 Generation

Electricity does not exist as a natural resource and therefore it is necessary to generate it. Generation is the activity through which electricity is produced in the generators.

Generators extract the power from primary sources (coal, natural gas, wind…) and transform it into electricity. This activity also includes the provision of ancillary services.

The transformation of energy extracted from primary sources into electricity is made through different technologies, which can be classified into three categories according to the time when they operate during the day:

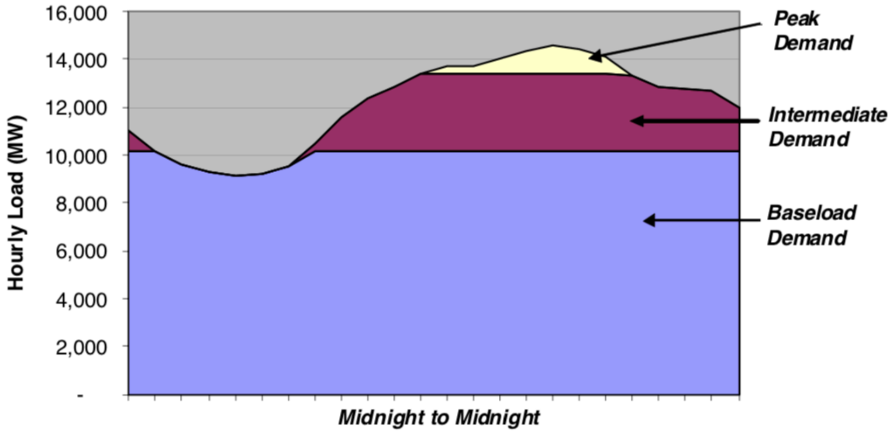

Fig. 2.2.1 Illustrative load curve [6]

- **Baseload units**: they are supposed to be permanently operating and are only shut down during maintenance periods. They are usually large power stations and have high fixed costs and low variable costs. These units are usually nuclear plants and coal plants.
- **Intermediate units**: these units can rapidly change their output to match the change in demand. They also serve as "spinning reserve" units, which are running but not putting power on the grid, so they are ready anytime an unpredicted peak in demand takes places or other units go off-line due to breakdowns. They are very efficient plants but operate with expensive fuels. These units are usually combined cycle plants.
- **Peaking units**: these units are the most expensive to operate but can startup or shutdown almost instantaneously to meet the brief peaks in demand. They also serve as "spinning reserve" units and typically operate for only a few hundred hours a year. These units are relatively inefficient and burn an expensive fuel, having high variable costs. They use combustion turbines that can either be used stand-alone as a peaking unit, or as a part of a more complex combined cycle plant used as an intermediate unit.

The so-called “variable renewable” power plants (wind and solar) do not fully suit into any category described above. They have very low variable costs, so they should ideally displace generation from intermediate and peaking units, which have high variable costs but, since it is not possible to control when this power plants generate electricity, they sometimes displace baseload units’ generation. [6]

The Spanish energy production park is quite diversified: in 2018, 24.9 % of installed capacity was combined cycle, 23.4 % wind, 17.3 % hydraulic, 9.7 % coal, 7.2 % nuclear, 6.8 % solar, and 6.3 % and 1 % of other non-renewable[2] and other renewables technologies. [7]

Nuclear	7,2%	Eólica	23,4%
Carbón	9,7%	Hidráulica	17,3%
Ciclo combinado	24,9%	Solar fotovoltaica	4,5%
Cogeneración	5,8%	Solar térmica	2,3%
Residuos no renovables	0,5%	Otras renovables	0,9%
Turbinación bombeo	3,4%	Residuos renovables	0,1%

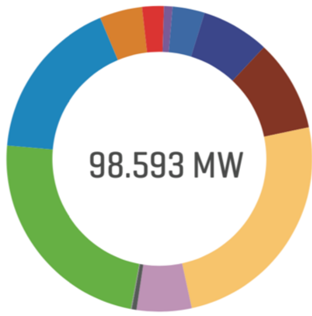

Fig. 2.2.2 Installed capacity shares in 2018

All renewable technologies added up to 48.9 % of total installed capacity in the Spanish Peninsula.

2.2.2 Transmission

It consists on transporting large amounts of energy from generation units to consumption centers, at a very high voltage. In Spain, the transmission network is made with transmission lines of a voltage higher or equal to 220 kV. The international and peninsular to extra-peninsular interconnections are also included in the transmission network no matter what their voltages are.

[2] Includes Cogeneration, Residues, and Fuel/Gas.

The transmission network is more critical than the distribution one: if there is a breakdown in it, it affects a lot more consumers, so that is why it is meshed instead of radially distributed.

Law 17/2007, of July 4th, confirmed the status of REE as the manager of the transmission grid and attributed it the function of sole transmission agent under a regime of exclusivity. As manager of the transmission grid, REE is responsible for developing and enlarging the grid, carrying out its maintenance and managing the transmission of electricity between external systems and the Spanish peninsula and guaranteeing third party access to the transmission grid under equal conditions.

The transmission grid of REE is comprised of more than 43,000 kilometers of high voltage electricity lines and more than 5,000 substation bays, and more than 85,000 MVA of transformer capacity. [8]

2.2.3 Distribution

Electricity is supplied to final consumers from the transmission network through the distribution one. The distribution voltage is lower than that of the transmission lines. Its network is stablished in a radial way in its lowest voltage levels, where small consumers that are not necessarily experts are connected. This activity is regulated according to Law 24/2013, of December 26th.

Facilities that are part of the distribution network are those that do not belong to a private citizen and have a nominal voltage lower than 220 kV. It is generally divided into delivery network (132, 66 or 45 kV), medium voltage, and low voltage network (<1kV), according to the nominal tension of the different facilities.

There are 347 companies serving approximately 29 million users in Spain. There are two clearly differentiated types of companies: large utilities, which supply more than 97% of users and take energy from generation and transmission systems; and smaller utilities which feed from lower voltage levels. The first group is composed of 5 companies, while the second is formed by 342 [9]. These companies are responsible for the maintenance of medium and low voltage networks, ensuring the quality of the supply, fixing the possible faults, maintenance of electricity meters that are rented to consumers, reading of electricity meters, and executing subscribes and unsubscribes, change of owner and change of tariff. The client is not capable of choosing the company that provides this service, it is stablished by areas. [10]

2.2.4 Commercialization

All activities related with the sale of energy to the end users. Retailers sell the electricity to their customers who can freely choose the company they want to buy it from. Retailers are those companies that, accessing to transmission or distribution networks, purchase energy to sell it to its customers, other agents of the system or to execute international interchanges.

Retailers are responsible for purchasing the electricity, providing electricity to their customers through distribution network, and turning over through the readings of the electricity meters that the corresponding distribution company sends to them. [10]

2.2.5 Demand

It is the final consumption of electricity from end users. A continuous balance between the electricity demanded and generated must be reached, since it is not storable in large quantities.

Some independent parameters, as temperature or labor, have an important effect on the electricity demand. The growth of the industrial sector is strongly related with an increase in the energy demand.

In the Spanish Peninsula, electricity demand keeps increasing since 2014, after a period of recession because of the economic crisis.

	Demanda b.c.		Componentes (%)		
	GWh	∆ Anual (%)	Laboralidad	Temperatura	Corregida
2014	243.174	-1,1	0,0	-1,0	-0,1
2015	247.970	2,0	-0,1	0,4	1,7
2016	249.680	0,7	0,6	0,1	0,0
2017	252.506	1,1	-0,3	-0,2	1,6
2018	**253.495**	**0,4**	**-0,1**	**0,2**	**0,3**

Fig. 2.2.3 Evolution of peninsular electricity demand (TWh) [7]

In 2018, temperature had an impact of 0.2 % over the electricity demand, which made it the most relevant factor for its increase. Nuclear technology was the one that contributed the most to cover the demand. This year, there was an underproduction of energy, so a 4.3 % of the demand needed to be cover by imported energy from other countries.

2.3 Agents

The electricity system is a very complex system where many agents are implicated. The main ones are producers, system operators, market operators, distributers, and retailers. In Spain, there are a few big corporations implicated in all liberalized sections of the electricity system, so they produce, distribute and commercialize energy.

2.3.1 Producers

Producers are those that generate the electricity from primary sources of energy. It is a liberalized sector, where many companies operate, although three large corporations (Endesa, Iberdrola and EDP) produced 57 % of the energy in 2017 [5], converting it into an oligopoly.

2.3.2 System Operators

REE is the Spanish system operator. It is the one in charge of the transmission network and the operation of the system. As explained before, transmission is a natural monopoly, so REE is the sole operator of it. It continuously coordinates production and transport of electricity to cover the demand.

2.3.3 Market Operators

A market operator is responsible for managing the market where energy is bought and sold. OMIE is the market operator in Spain. Through an online platform many agents participate in the process: sellers make selling offers and buyers buying offers and when they match a price for the MWh is established. Fig. 2.3.1 illustrates this process.

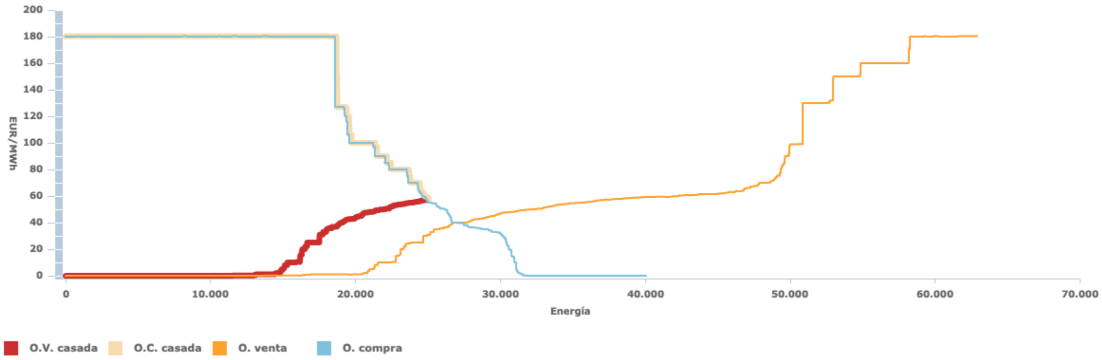

Fig. 2.3.1 Matching process for hourly price in the daily market

The price is adjusted according to some technical restrictions: MWs offered by generators enter the pool in increasing price order (cheapest first), so the latest to enter (the most expensive one) sets the energy price, which corresponds to its variable costs.

2.3.4 Distributers

They construct, maintain and operate the distribution facilities that transport electricity to consumer points. Distribution is also a natural monopoly, so there is a restricted number of companies that operate as distributers: Endesa, Iberdrola, Unión Fenosa, HC Energía, and Enel Viesgo.

Fig. 2.3.2 Territories of each distributer [11]

The compensation for their services is regulated by law and does not respond to any market logic.

2.3.5 Retailers

For those who are in the liberalized market, retailers are companies that supply electricity to them at a price that is previously agreed between the two parts. Small clients whose contracted power is lower than 10 kW can take advantage of the so called *Precio Voluntario para el Pequeño Consumidor* (PVPC) which is calculated by REE according to the average price of electricity, so it varies every month. PVPC is offered by retailers that are out of the liberalized market, which are called *Comercializadora de Referencia*. These companies are EDP Comercializadora de Ultimo Recurso, Alumbrado Eléctrico de Ceuta Comercializadora de Referencia, CHC Comercializadora de Referencia, and Teramelcor.

By 2017, four companies (Endesa, Iberdrola, EDP and GNP) bought 78 % of the energy generated in 2017 [5], so the energy market can be considered as an oligopoly.

3. DATA SELECTION CRITERION

3.1 Selection of Base Scenarios

To carry out this study, data of generation and demand has been taken from two different years: 2014 and 2017. These years have been chosen because they represent opposite weather condition scenarios, being 2014 very rainy and 2017 very dry.

In 2014, hydraulic energy production was above average levels. On the other hand, 2017 hydraulic energy production was very low.

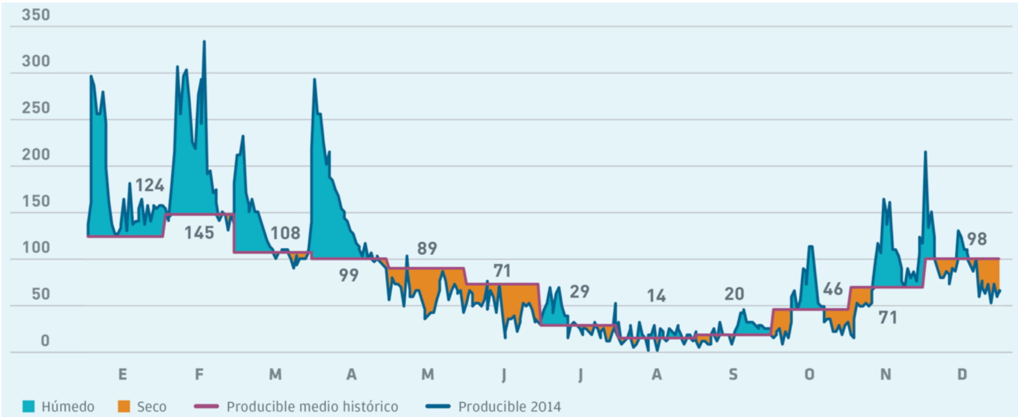

Fig. 3.1.1 Producible hydroelectric power in 2014 [12]

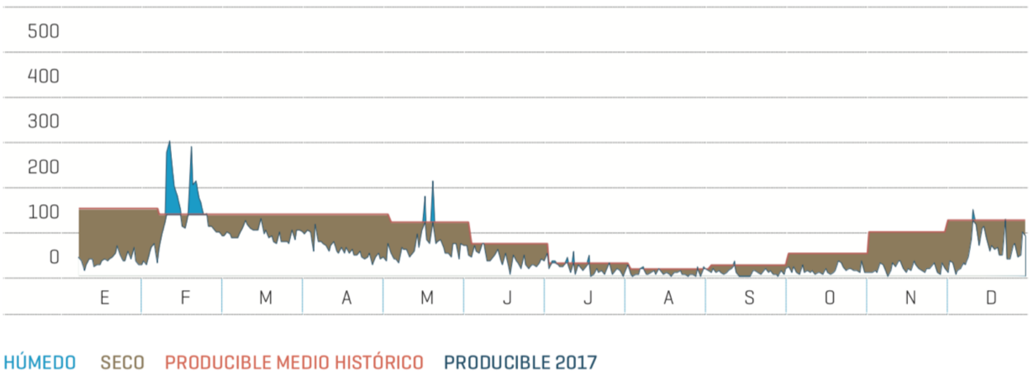

Fig. 3.1.2 Producible hydroelectric power in 2017 [13]

These two different scenarios imply different energy generation shares of technologies present in the mix, as well as different installed capacities of conventional technologies when data is projected to 2030 values.

3.2 Base Scenario A: 2014

2014 was an extremely hot year, with an average temperature of 15.96 ºC, which implies 1.33 ºC more than historic average.

From an economic perspective, Spanish GDP grew 1.4 %, changing the negative trend of 2013. Industry sector grew 1.7 % and service sector 2.7 %.

2014 was a wet year, having a hydraulic energy production 17 % larger than historic average.

3.2.1 Installed capacities

Installed capacity got slightly reduced, ending with 102,262 MW, which was 0.1 % less than previous year. Coal technology's installed capacity was the one that got reduced the most, losing 159 MW.

TABLE 3.2.1 INSTALLED CAPACITIES

TECHNOLOGY	2014 (MW)	% 14/13
Hydraulic	19,896.0	0.0
Nuclear	7,866.0	0.0
Coal	10,972.0	-1.4
Fuel/Gas	520	0.0
Combined Cycle	25,348.0	0.0
Wind	22,845.0	0.0
Photovoltaic	4,428.0	0.1
Solar thermal	2,300.0	0.0
Thermal renewable (1)	1,012.0	3.9
Cogeneration and rest (2)	7,075.0	-0.1
Total	**102,262.0**	**-0.1**

Source: "El Sistema eléctrico español (2014)" [12]

(1) Includes biogas, biomass, and geothermal.

(2) Includes cogeneration and residues.

On the other hand, thermal renewable's installed capacity experiments the larger increase (3.9 %), with 37.98 MW more installed. Although it is the largest percentage increase, its impact is quite insignificant.

3.2.2 Energy balance

During 2014, annual electricity demand kept decreasing with respect to the previous year, ending with 243,530 GWh (1.2 % less than 2013). This decrease was mainly due to temperature effects, since winter was not too cold and summer not too hot.

TABLE 3.2.2 ENERGY BALANCE

TECHNOLOGY	2014 (GWh)	% 14/13
Hydraulic	42,297.0	5.5
Nuclear	57,376.0	1.0
Coal	44,064.0	10.7
Fuel/Gas	-	-
Combined Cycle	22,060.0	-12.1
Consumption in generation	-6,561	4.6
Wind	50,630.0	-6.8
Photovoltaic	7,794.0	-1.6
Solar thermal	4,959.0	11.6
Thermal renewable (1)	4,718.0	-6.9
Cogeneration and rest (2)	25,596.0	-20.1
Net generation	**253,564.0**	**-2.6**
Pumping consumption	-5,330.0	-10.5
Peninsula-Baleares link	-1.298.0	2.3
International exchanges	-3,406.0	-49.4
Demand (b.c)	**243,530.90**	**-1.2**

Source: "El Sistema eléctrico español (2014)" [12]

(1) Includes biogas, biomass, and geothermal.

(2) Includes cogeneration and residues.

Net generation reached 253,564 GWh, which is 2.6 % less than 2013. Nuclear energy was the one that generated the most (57,376 GWh), followed by wind energy (50,630 GWh) and coal energy (44,064 GWh).

Focusing on electricity demand coverage, nuclear energy was the technology with the largest share (22 %), followed by wind energy (20.3 %) and coal (16.5 %). Renewable technologies covered the 42.8 % of the total demand, which implies an increase of 0.6 % with respect to the previous year.

3.3 Base scenario B: 2017

2017 registered higher temperatures in summer and softer in winter with respect to the historic average: 43.4 % of the days had much hotter temperatures than average, especially during June, July and August; while only 8.5 % of the days had colder temperatures than average.

From an economic perspective, Spanish GDP grew a 3.1 % with respect to the previous year, following the increasing trend established in the previous years. Industry sector grew 2.2 % and service sector decreased 0.2 %.

2017 was an extremely dry year, having a decrease in hydraulic energy production of 49.1 %, which is the lowest value since 2005.

3.3.1 Installed capacities

Installed capacity got reduced by a 0.6 %, mainly due to the closure of nuclear power plant Santa María de Garoña. Final installed capacity for the peninsular system in 2017 reached 99,877 MW.

TABLE 3.3.1 INSTALLED CAPACITIES (MW)

TECHNOLOGY	2017 (MW)	% 17/16
Hydraulic	17,030.0	0.0
Pumping	3,329.0	0.0
Nuclear	7,117.0	-6.0
Coal	9,536.0	0.0
Fuel/Gas	-	-
Combined Cycle	24,948.0	0.0
Wind	22,922.0	0.1
Photovoltaic	4,439.0	0.0
Solar thermal	2,304.0	0.0
Other renewables [1]	852.0	0.1
Cogeneration	5,818.0	-2.8
Non-renewable residues	459.0	0.0
Renewable residues	123.0	0.0
Total	**98,887.0**	**-0.6**

Source: "El Sistema eléctrico español (2014)" [13]
(1) Includes biogas, biomass, and geothermal.

The only technologies that increased their installed capacity were the so called "Other Renewables", which include biogas, biomass and residues.

3.3.2 Energy balance

Annual electricity demand kept increasing during 2017, ending at 252,740 GWh, which is 1.1 % more than the previous years. This increase happened mainly due to economic growth, since temperature had a negative impact in the increase of electricity demand, having fewer cold days during 2017.

TABLE 3.3.2 ENERGY BALANCE (GWh)

TECHNOLOGY	2017 (GWh)	% 17/16
Hydraulic	18,361.0	-49.1
Turbine pumping	2,249.0	-28.2
Nuclear	55,609.0	-0.9
Coal	442,593.0	21.0
Fuel/Gas	-	-

Combined Cycle	33,855.0	31.8
Wind	47,498.0	0.4
Photovoltaic	7,988.0	5.4
Solar thermal	5,348.0	5.5
Other renewables (1)	3,603.0	5.5
Cogeneration (2)	28,134.0	8.7
Non-renewable residues	2,459.0	-0.5
Renewable residues	728	12.1
Net generation	**248,424.0**	**0.0**
Pumping consumption	-3,675.0	-23.7
Peninsula-Baleares link	-1.179.0	-5.7
International exchanges	9,171.0	19.6
Demand (b.c)	**252,740.0**	**1.1**

Source: "El Sistema eléctrico español (2014)" [12]

(1) Includes biogas, biomass, and geothermal.

(2) Includes cogeneration and residues.

Net generation reached 248,424 GWh, being almost the same as previous year. The largest variation happened with hydraulic generation, which decreased by 49.1 %, making combined cycle and coal to increase their production by 31.8 % and 21 % respectively.

Focusing on the electricity demand coverage, nuclear energy was the most relevant technology, covering 22.4 % of the demand, followed by wind energy (19.1 %) and coal energy (17.1 %). It is very relevant the lacking coverage of hydraulic energy (7.4 %), which made nonrenewable technologies to cover a larger share of the demand. That fact translated into just a 33.7 % of renewable technologies coverage, 6.6 % less than the previous year.

4. STUDY CASES

To cover the thermal demand that would represent 20 % of energy generation in 2030, three different scenarios have been studied: nuclear, combined cycle and coal technologies; combined cycle and coal technologies; only combined cycle technology.

In each scenario, a sensitivity analysis on how interest rate affects the results has been performed, considering three different possibilities: 3 %, 7 % and 10 %. All scenarios have been studied for Base Scenario A (2014 data) and Base Scenario B (2017 data), from which data has been scaled to 2030.

4.1 Study Case 1: nuclear, combined cycle and coal as conventional technologies

For the first scenario, nuclear, combined cycle and coal technologies are the conventional technologies considered to cover the thermal demand. Taking into account their fixed and variable costs, an economically optimum thermal generation park is obtained, and its costs are analyzed and compared to those of the base scenarios.

4.2 Study Case 2: nuclear out of the mix

This study case is divided into two parts: a first part where investment costs that would take nuclear technologies out of the mix are calculated; and a second part where an economically optimum thermal generation park, considering the previously calculated nuclear technology investment costs, is obtained and analyzed.

4.3 Study Case 3: combined cycle as the only conventional technology

Finally, a situation where only combined cycle operates as the conventional technology covering the thermal demand is studied. In this scenario, combined cycle technology would be the last one entering the generation mix, so its variable costs would be the ones determining the price of electricity. Selecting some random units and analyzing their power offers in the energy market, it is possible to build an equivalent offer curve for combined cycle technology where the price variation with respect to power generated can be shown.

4.4 Justification of study cases raised

Study case 1 has been chosen because it lays out a situation where three very common technologies in nowadays generation mix represent the conventional technologies needed to assure the system's well-functioning in a high penetration of renewable technologies scenario. These three technologies are present in almost all generation mixes of different countries and, for that reason, it is interesting to know which ones are more economically optimal compared with the others.

Study case 2 has been selected because of the opaque atmosphere that surrounds nuclear technology costs. As it is said in article *Reviewing electricity production cost assessments* [14], in which twelve different studies of production costs from different power generating technologies are reviewed, costs of nuclear technology can oscillate quite a lot depending on what source is checked. This article shows how its investment costs can oscillate between 3,000 to almost 5,000 $/kW, and its variable costs between 10 and 20 $/MWh. This uncertainty on its costs, together with the controversy about its environmental impact that is quite spread in some society sectors, make it interesting to analyze a situation when nuclear technology is no longer in the generation mix.

Study case 3 has been chosen because it opens up the opportunity to go one step further regarding the economic analysis performed. Considering only one conventional technology to cover the thermal demand, it is possible to calculate an hourly price of electricity rather than an average value, so a deeper analysis can be performed. In this scenario, the deficit in incomes of generators if they only perceived the price of electricity they generated can be calculated, so it is possible to provide a value for the payments by capacity mechanisms that the system must provide.

5. CALCULATIONS

All calculations required in this study have been performed with Matlab. Base scenarios have been considered as staring point to perform all calculations, so the same process has been followed for both. Many calculations are the same for both base scenarios, so a unique explanation for them will be provided.

There are just a few situations where calculations differ depending on the base scenario, which in that case will be explained separately.

5.1 Uploading vectors of generation and demand

Data from E·SIOS, which is an information system designed by REE, is taken and processed to obtain a set of vectors containing generation and demand of base years. These vectors are:

- V_Demanda: obtained by subtracting pumping consumption from the energy demand at the generation terminals in an hourly basis.
- V_Nuclear: hourly generation of nuclear technologies.
- V_Carbon: hourly generation of coal technologies.
- V_CicloCombinado: hourly generation of combined cycle technologies.
- V_Cogeneracion: hourly generation of cogeneration technologies.
- V_FuelGas: hourly generation of fuel and gas technologies.
- V_Residues: hourly generation of residues technologies.
- V_Eolica: hourly generation of wind energy technologies.
- V_Fotovoltaica: hourly generation of photovoltaic technologies.
- V_Termosolar: hourly generation of solar thermal technologies.
- V_Hidraulica: hourly generation of hydraulic energy technologies.
- V_OtrasRenovables: hourly generation of biogas, biomass, hydraulic marine, and geothermal technologies.
- V_Generacion: obtained by summing all generation vectors.

- V_Renovables: vector obtained by summing renewable technology vectors (V_Eolica, V_Fotovoltaica, V_Termosolar, V_Hidraulica, V_OtrasRenovables).

These vectors contain the information of generation and demand of base scenarios, which is needed to obtain the extrapolated values of 2030 that are analyzed according to different scenarios exposed.

5.2 Operation and order of vectors, obtaining of annual values of generation and demand

To see how load-duration curve varies when subtracting different renewable technologies, four new vectors are created and sorted:

- V_SinHidro: obtained by subtracting hydraulic energy generation vector from demand vector.
- V_SinEolica: obtained by subtracting wind generation vector from demand vector.
- V_SinSolar: obtained by subtracting photovoltaic and solar thermal generation vectors from demand vector.
- V_Termica: obtained by subtracting all renewable generation vectors from demand vector. It represents the energy that is generated by non-renewable technologies.

As it can be appreciated in Fig. 5.2.1 and Fig. 5.2.2, hydraulic energy generation has a deeper impact in 2014, since it was a wet year. The other renewable technologies have a similar impact in both years.

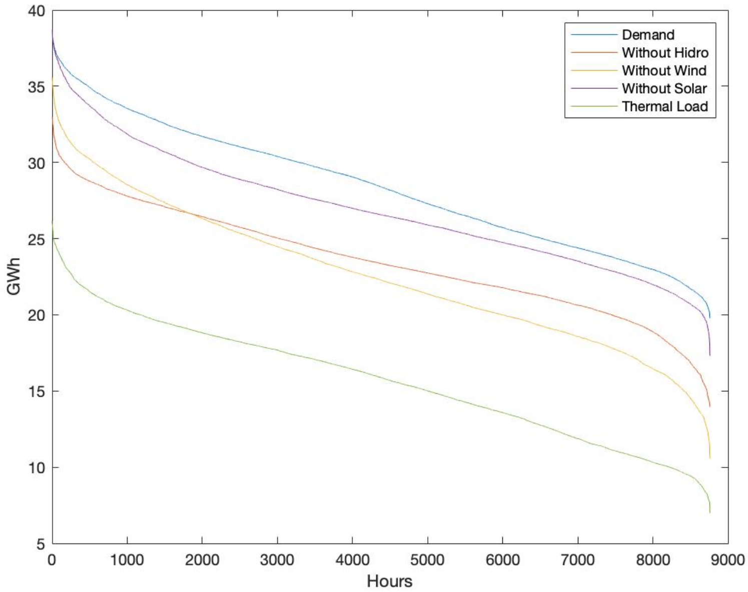

Fig. 5.2.1 Load-duration curve evolution 2014

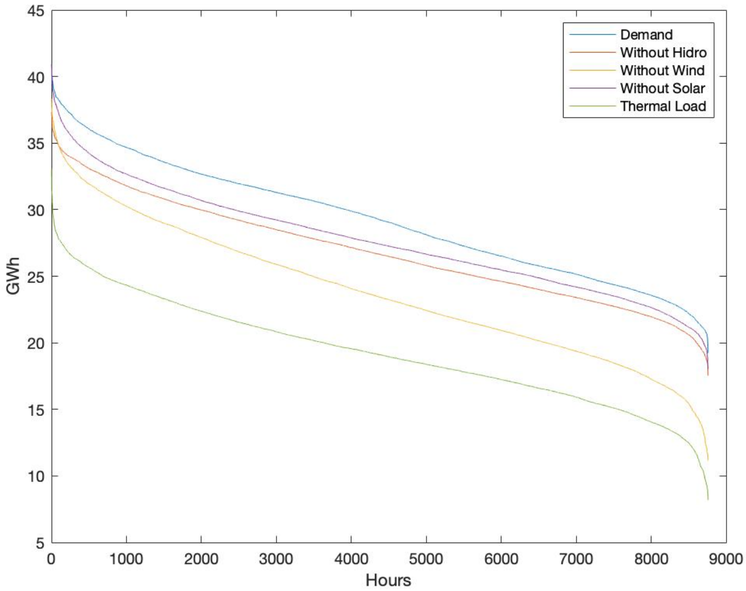

Fig. 5.2.2 Load-duration curve evolution 2017

5.3 Scaling demand and generation to 2030, making renewable generation cover the 80 % of total generation.

Demand vector is scaled to 2030 considering an annual increment of 0.9 %, as it is stated in the report *Comisión de Expertos de Transición Energética* [3].

To make renewable generation represent 80 % of total generation in 2030, an iterative process has been performed. Firstly, all calculations are done with a tentative scaling factor, because it is not easy to predict what scale factor will make set renewable technologies represent the 80 % of final generation values obtained, since a minimum value for thermal generation has to be introduced to assure electricity supply and hence there is a considerably large amount of energy that will be produced but not demanded. The scaling factor has been adjusted manually until the desired values for renewable technologies generation are achieved. These scaling factors are different from each base scenario:

- 2014: Scaling Factor = 1.06
- 2017: Scaling Factor = 1.08

Once the value for renewable technologies generation as a whole is obtained, the value of each renewable technology generation must be calculated. To do so, three hypotheses are considered:

1) Installed capacity of hydraulic technology will not vary, and its energy production is assumed to be constant until 2030.
2) Other renewables will remain constant, as well as their installed capacities.
3) Once hydraulic and other renewables generations are established, the remaining energy that must be covered by renewable technologies is distributed in the following way: wind energy represents 42.3 %, photovoltaic represents 54.56 %, and solar thermal represents 3.14 %.

The first hypothesis is assumed because areas where hydraulic energy power plants can be installed are quite limited. That is one of the main reasons why two years with very different hydraulic energy production are considered as base scenarios.

The third hypothesis is formulated considering the values that the report *Comisión de Expertos de Transición Energética* gives in its estimation for 2030:

	DG 2030	ST 2030
Demanda (TWh)	**296**	**285**
Capacidad total instalada (MW)	**149.439**	**143.737**
Nuclear	7.117	7.117
Carbón	847	4.660
Ciclo combinado	24.560	24.560
Hidráulica (+bombeo)	23.050	23.050
Eólica	31.000	31.000
Fotovoltaica	47.150	40.000
Termosolar	2.300	2.300
Resto renovables	2.550	2.550
Cogeneración y otros	8.500	8.500
Baterías	2.358	0

Fig. 5.3.1 Results for reference scenarios [3]

Values for scenario "Sustainable Transition" (ST 2030) are the ones considered. In this scenario, from the total installed capacity of renewable technologies (hydraulic energy, wind energy, photovoltaic, solar thermal and other renewables), 73.3 MW are from wind energy and solar energy. Wind energy represents 42.3 % of this amount, photovoltaic energy 54.56 % and solar thermal 3.14 %. To calculate the capacity of these technologies that will be installed in 2030, these following steps have been followed:

5.3.1 Calculation of capacity factors

Capacity factors of wind energy, photovoltaic energy and solar thermal energy are calculated with equation

$$Capacity\ Factor = \frac{Average\ power\ generated\ in\ a\ year}{Installed\ capacity}$$

Data of average power generated in a year and installed capacity of each technology is taken from base scenarios, and an average value of capacity factors obtained is calculated. These average values obtained are:

- Capacity factor of wind energy: 0.24
- Capacity factor of solar thermal energy: 0.27
- Capacity factor of photovoltaic energy: 0.20

which are the capacity factors employed along the study.

5.3.2 Calculation of installed capacities of wind and solar technologies in 2030

First of all, the value of total generation of solar and wind technologies previously obtained is converted into average power generated by these technologies in 2030,

$$P_{sw}\ [GW] = Gen_{sw}\ [TWh] * \frac{1000\ [GW]}{8760\ [h]} \tag{1}$$

where P_{sw} stands for average power generated by solar and wind technologies and Gen_{sw} for their total generation. A relation between average power generated by wind and solar technologies and their installed capacities is established,

$$P_{sw}\ [GW] = C_w \cdot 0.24 + C_{ph} \cdot 0.20 + C_{ts} \cdot 0.27\ [GW] \tag{2}$$

being C_w, C_{ph} and C_{ts} total installed capacities of wind, photovoltaic and thermal solar technologies, respectively. As stated before, installed capacities of these technologies can be rewritten as a fraction of total installed capacity of these three technologies as a whole according to the values provided by the already mentioned report,

$$\begin{cases} C_w\ [GW] = C_t \cdot 0.423 \\ C_{ph}\ [GW] = C_t \cdot 0.5456 \\ C_{ts}\ [GW] = C_t \cdot 0.0314 \end{cases} \quad C_t\text{: } total\ installed\ capacity\ of\ solar\ and\ wind \tag{3}$$

so equation (2) can be rewritten as:

$$P_{sw}\ [GW] = C_t \cdot 0.423 \cdot 0.24 + C_t \cdot 0.5456 \cdot 0.20 + C_t \cdot 0.0314 \cdot 0.27\ [GW] \tag{4}$$

In this way, it is possible to solve the equation (2) for C_t and then substitute it in equation (3) to obtain the installed capacities of wind, photovoltaic and solar thermal technologies individually.

5.3.3 Calculation of annual generation of wind and solar technologies in 2030 and scaling of base scenario vectors to 2030 values.

Multiplying each installed capacity by its capacity factor, power generated in 2030 by solar and wind technologies is obtained. Utilizing the conversion factor described in equation (1), total generation of these technologies in that year is calculated. Finally, the scalar factor that relates total generation of solar and wind technologies in base year and 2030 is obtained for each technology,

$$Scalar\ Factor = \frac{Gen_{2030}}{Gen_{base}} \tag{5}$$

and is used to scale the base year vectors to 2030 values.

5.4 Setting a minimum for thermal generation in 2030

Subtracting wind, photovoltaic, solar thermal and other renewables generations from demand in 2030, thermal generation is obtained, as it has been explained before. As generations of renewable technologies have been manipulated to cover the 80 % of the total energy generation, this subtraction shows negative values in some hours.

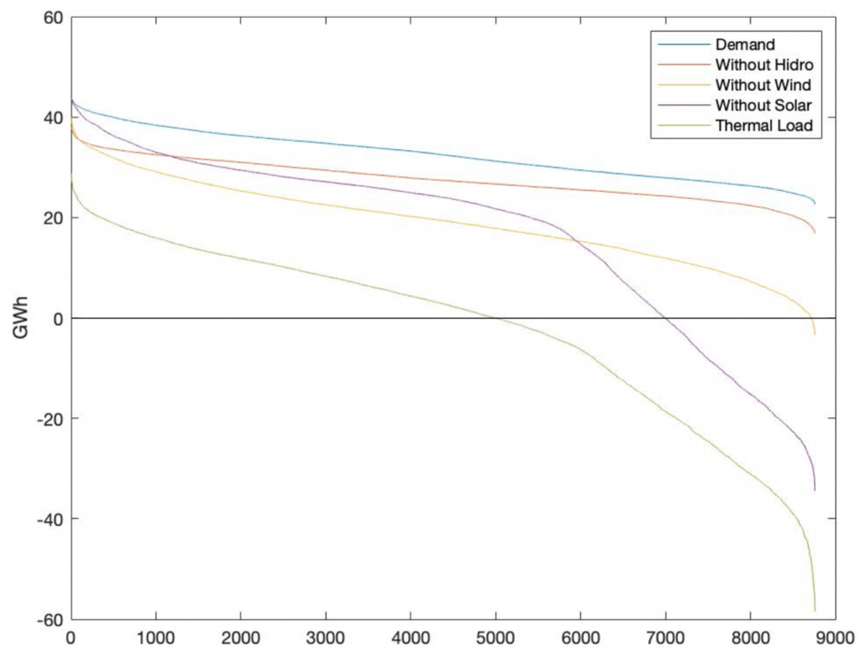

Fig. 5.4.1 Load-duration curve 2030 (base 2014)

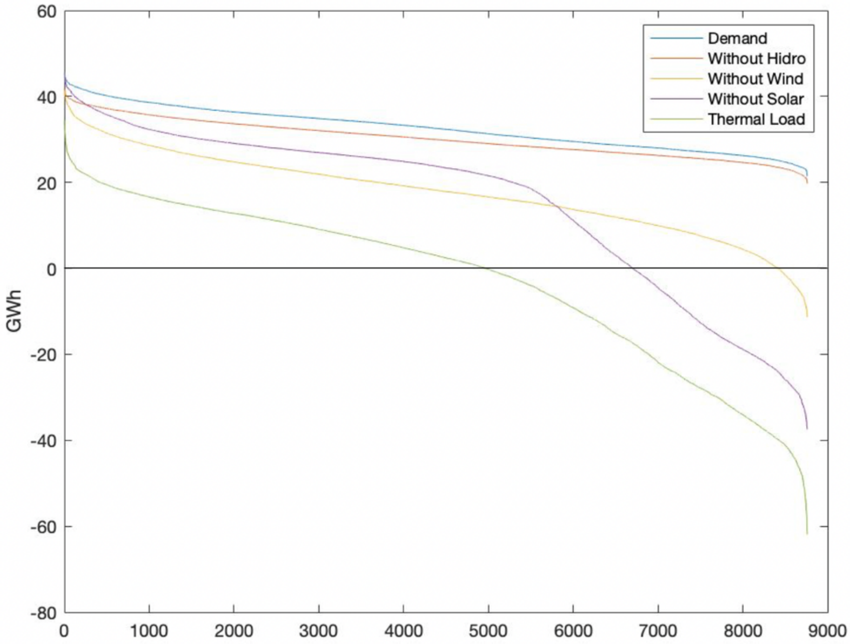

Fig. 5.4.2 Load-duration curve evolution 2030 (base 2017)

A minimum of 5 GWh must be produced by conventional technologies to ensure the correct functioning of the system. This fact will produce an unavoidable energy spillage which derived from producing energy when it is not demanded.

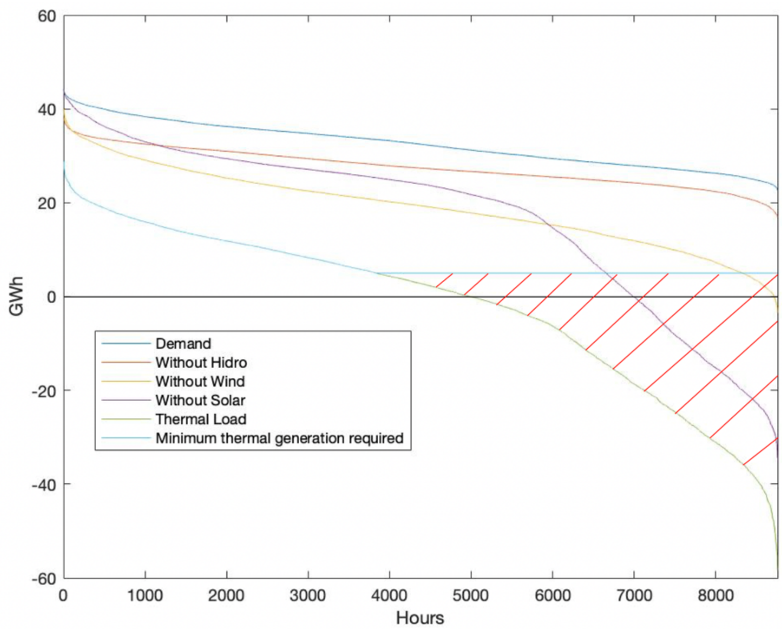

Fig. 5.4.3 Energy thrown away in 2030 (base 2014)

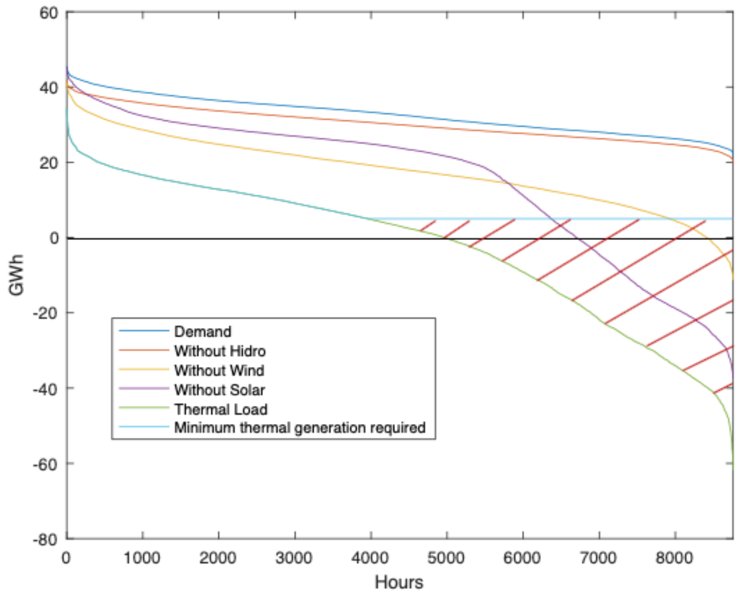

Fig. 5.4.4 Energy thrown away in 2030 (base 2017)

This energy surplus could not be considered as a waste if it could be stored or used by other countries through an interconnected network.

5.5 Case study 1: optimization of thermal park with three conventional technologies

Once the thermal load vector, considering the required minimum of 5 GWh generation, is obtained, an optimization process to find what conventional technologies will operate is performed, taking into account their fixed and variable costs. This optimization process only attends to economic reasons, not considering other social costs that could play an important role when designing an energy generation park.

5.5.1 Stepping curve approximation for thermal load curve

To solve the optimization problem, *linprog* Matlab function is used. This function works with some specific parameters that will be presented in the following lines.

The thermal load curve is divided into several time intervals which have an uneven duration but a similar demand level. The steps of the stepped curve are each of the values of vector D_t, which is defined as:

$$D_t = D_{max} - \frac{D_{max} - D_{min}}{T} \cdot (t - 1) \tag{6}$$

where D_{max} and D_{min} are the maximum and minimum demand for the year, and T is the number of intervals and t is the index of time intervals, which is a vector that goes from 1 to T. D_{max} and D_{min} differ from one base scenario to another:

$$Base\ 2014: \begin{cases} D_{max} = 28{,}808.6 \\ D_{min} = 5{,}000 \end{cases} MWh \qquad Base\ 2017: \begin{cases} D_{max} = 34{,}839.5 \\ D_{min} = 5{,}000 \end{cases} MWh$$

while T is the same for both, being 100.

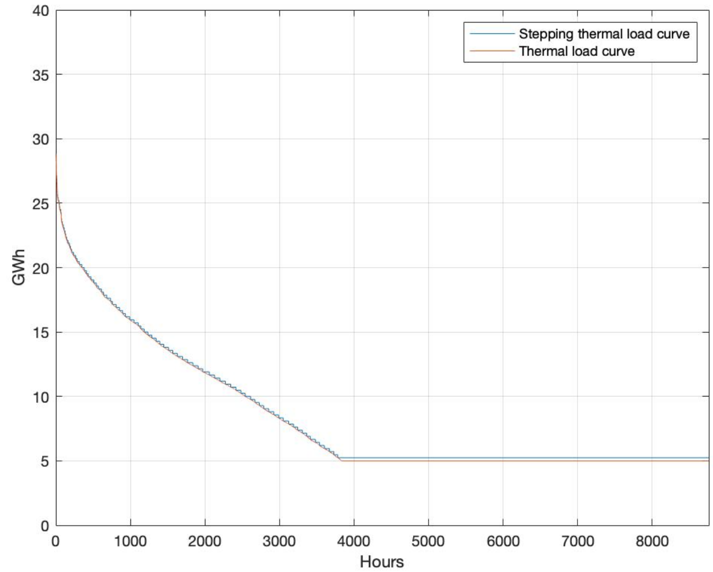

Fig. 5.5.1 Stepping approximation for Thermal Load Curve (base 2014)

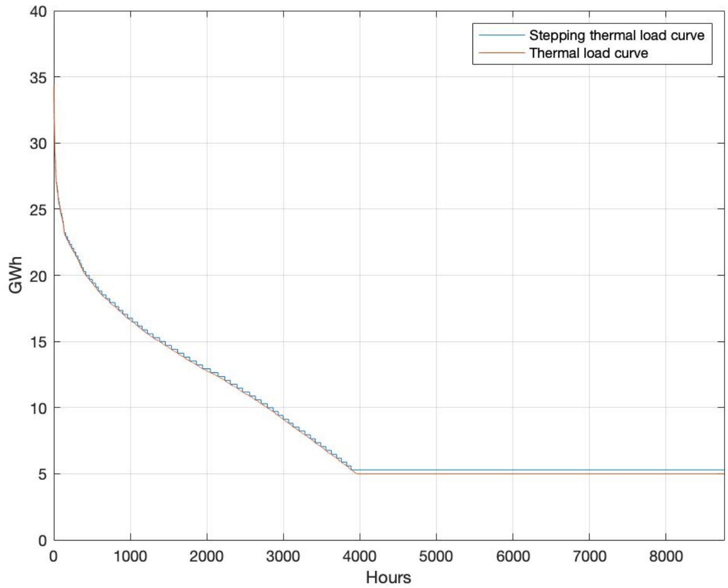

Fig. 5.5.2 Stepping approximation for Thermal Load Curve (base 2017)

5.5.2 Statement of equations that defines the optimization process

The planning of a thermal generation park can be stated in a general manner as an optimization problem that can be expressed in the following way:

$$min_{P_{nt},P_n} \sum_{t=1}^{T} \sum_{n=1}^{N} N_t CV_n P_{n,t} + \sum_{n=1}^{N} CF_n P_n$$

$$\begin{aligned} &\textstyle\sum_{n=1}^{N} P_{n,t} = D_t && t = 1, \dots, N_t \\ &P_{n,t} - P_n \leq 0 && n = 1, \dots, N; t = 1, \dots, N_t \\ &P_n \geq 0 && n = 1, \dots, N \\ &P_{nt} \geq 0 && n = 1, \dots, N; t = 1, \dots, N_t \end{aligned} \tag{7}$$

where symbols have the following meaning:

n	Technology index
t	Time interval index
N	Number of technologies
T	Number of time intervals
N_t	Relative duration of each time interval t
CV_n	Variable costs of technology n [$/MWh]
CF_n	Fixed costs of technology n [$/MWh]
$P_{n,t}$	Average power produced by technology n on time interval t [MW]
P_n	Installed capacity of technology n
D_t	Average demand on time interval t

Investment and variable costs (CI and CV, respectively) are extracted from paper *Toward Fully Renewable Electric Energy Systems* [15], which at the same time takes this data from *Energy Technology Perspectives 2010*[3] [16], where they are broken down for

[3] Report *Energy Technology Perspectives 2010* has been selected because, although it is quite old, it has a free access and, most importantly, fixed and variable costs of all technologies included in this study are broken down, which in the following reports are not.

many different technologies. Investment costs are the overnight cost of a power plant, which represent the cost of a construction if no interest was incurred during construction period; while variable costs include fuel, emission, and operating and maintenance costs. The following equation is applied to convert investment costs into fixed costs:

$$CF = \frac{1}{8.76} \cdot \frac{r \cdot CI}{1 - \left(\frac{1}{1+r}\right)^{x}} \ [\$/MWh] \tag{8}$$

where r represents the interest rate and x is the plant life-time. The investment and variable costs considered for the resolution of this optimization problem are:

- $CI \begin{cases} CI_n = 3000 \\ CI_{cc} = 750 \\ CI_c = 2500 \end{cases} \quad [\$/kW]$
- $CV \begin{cases} CV_n = 12 \\ CV_{cc} = 47 \\ CV_c = 26 \end{cases} \quad [\$/MWh]$

A sensitivity analysis is performed regarding three different values of r: 3 %, 7 % and 10 %. The plant life-time considered for nuclear, combined cycle and coal technologies are 60, 30 and 40 years respectively.

5.5.3 Solving the optimization problem with Matlab *linprog* function

Linprog is a Matlab function that finds the minimum of a problem specified by:

$$min_x \ f^T \text{ such that} \begin{cases} A \cdot x \leq b \\ Aeq \cdot x = beq \\ lb \leq x \leq ub \end{cases}$$

being f, x, b, beq, lb, and ub are vectors, and A and Aeq are matrices [17] .

For this particular problem, the function is defined as

$$[Sol] = linprog(f, A, b, Aeq, beq, lb) \tag{9}$$

which solves min $f' * Sol$ such that $A * Sol \leq b$, including equality constraints $Aeq * x = beq$ and defines a lower bound on Sol. The meaning of each of the *linprog* function parameters is the following:

- f: it is the coefficient vector. It represents the objective function $f' * Sol$. In this particular case, only three conventional technologies are considered, so f is defined as:
$$f = [N_t \cdot CV_n \quad N_t \cdot CV_{cc} \quad N_t \cdot CV_c \quad CF_n \quad CF_{cc} \quad CF_c]$$
being a column vector of length $T \cdot N + N$.
- A: it is a real matrix that specifies the linear inequality constraints. It is an M-by-N matrix, where M is the number of inequalities (length $T \cdot N$), and N is the number of variables (length of f). The inequalities considered are:
$P_{n,t} - P_n \leq 0$
$P_{cc,t} - P_{cc} \leq 0$
$P_{c,t} - P_c \leq 0$
- b: it is a real vector that specifies the linear inequality constraints. It is an M-element vector related to the A matrix. In this specific case, it is a column vector of length $T \cdot N$ with all its elements being 0.
- Aeq: it is a real matrix that specifies the linear equality constraints. It is an Me-by-N matrix, where Me is the number of equalities (length T), and N is the number of variables (length of f). The equalities considered are:
$P_{n,t} + P_{cc,t} + P_{c,t} = D_t$
- beq: it is a real vector that specifies linear equality constraints. It is an Me-element vector related to matrix Aeq. In this case, it is a column vector of length T and elements D_t.
- lb: it is a real vector that specifies the lower bounds. In this case, it is a column vector of length $T \cdot N + N$ (length of f) with all its elements being 0.

Once the function is executed, the column vector Sol is obtained, containing the values of $P_{n,t}$, $P_{cc,t}$, $P_{c,t}$, P_n, P_{cc}, and P_c.

5.5.4 Installed capacities and energy produced obtained from the optimization process

Installed capacities of each technology are obtained in the last three elements of vector Sol. Elements 1 to T of vector Sol constitute the vector of power produced in each time interval by nuclear technologies in 2030, elements (T+1) to (2· T) by combined cycle technologies, and elements (2· T +1) to (3· T) by coal technologies.

5.6 Study case 2: optimization of thermal park without nuclear technology

Investment costs (CI) value of nuclear technology is increased, for each interest rate considered, until the solution vector Sol shows a 0 value for its installed capacity. Doing so, the value of nuclear technology CI that would make it economically suboptimal for it to be part of the generation mix is obtained, for each interest rate considered. Everything else is performed in the exact same way as in Study case 1, explained above.

5.7 Costs of electricity for the two first study cases

Costs of electricity are calculated considering the LCOEs provided in report *Projected Costs of Generating Electricity* [18]. These LCOEs are calculated according to the following equation:

$$LCOE = \frac{\sum[(Capital_t + O\&M_t + Fuel_t + Carbon_t + D_t) \cdot (1+r)^{-t}]}{\sum MWh(1+r)^{-t}} \tag{10}$$

where different variables indicate:

$LCOE$	Levelized Cost of Energy
MWh	Amount of electricity produced in MWh, assumed constant
$(1+r)^{-t}$	Discount factor for year t (reflecting payments to capital)
$Capital_t$	Total capacity construction costs in year t
$O\&M_t$	Operation and maintenance costs in year t
$Fuel_t$	Fuel costs in year t
$Carbon_t$	Carbon costs in year t

D_t Decommissioning and waste management costs in year t

The values of LCOEs are contained in the following table:

TABLE 5.7.1 LCOEs OF TECHNOLOGIES PRESENT IN THE GENERATION MIX

TECHNOLOGY	LCOE ($/MWh)		
	3 %	7 %	10 %
Nuclear	51.7	80.53	109.32
Combined cycle	116.34	123.52	130.67
Coal	77.41	88.19	98.25
Cogeneration	94.09	122.89	149.08
Wind	81.51	102.19	119.96
Solar thermal	263.39	348.35	422.60
Photovoltaic	96.97	125.98	151.16
Hydraulic	59.08	83.19	90.70
Other renewables	126.30	124.58	165.58
Residues	229.28	285.34	336.46

Source: Projected costs of generating electricity [18]

With these LCOEs, costs of electricity can be calculated with

$$CT_n = LCOE_n[\$/MWh] \cdot E_n[MWh] \tag{11}$$

being n the technology index, CT_n total cost of technology n, and E_n the energy produced by technology n in a particular year. The LCOEs used for these calculations are those given for Spanish technologies, according to the already mentioned report. For those cases in which there is no information about some particular technologies in Spain, an average value of the LCOEs available of countries from the OECD is calculated. Values of LCOEs are taken for interest rates of 3 %, 7 % and 10 %, to match the sensitivity analysis that is performed in the study.

The average price of electricity is calculated through the following equation:

$$PM = \frac{\sum_{n=1}^{N} CT_n \;\; [\$]}{Anual\ Energy\ Generation\ [MWh]} \tag{12}$$

where annual energy generation is calculated by adding all energy generations of different technologies that operate in a particular year.

5.8 Study case 3: optimization of thermal park with combined cycle only

In this case, a different approach regarding the price of electricity is carried out. Until now, only one value for variable costs has been considered, so in the case of a system with only combined cycle as conventional technology, price of electricity would be constant. This does not happen in real life, since marginal costs vary depending on the production level. For this reason, in this study case a step further is taken: the price of electricity according to the level of energy production of combined cycle technology is found by modeling the marginal costs of an equivalent combined cycle unit, which represents all combined cycle units of the system.

Information of energy offered and offered sales[4] of different combined cycle units is obtained [19] to create an equivalent unit for the group of units previously selected, so a relation of Price ($/MWh) and Power (MW) can be established for energy that the conventional technologies, which in this case is only combined cycle, must cover. This relation provides a different price of electricity for any level of energy production, which in the end translates into an hourly price of electricity for the target year.

5.8.1 Uploading data of energy offered and offered sales

Data from hour 8 of December 1st, 2017 is obtained and eleven units are chosen among all combined cycle units operating in Spain, creating two-column arrays containing the energy offered in the first column and the price of this sold energy in the second one. These arrays are:

- V_ace3 → ACECA3
- V_ace4 → ACECA 4
- V_arcos2 → ARCOS 2
- V_arcos3 → ARCOS 3
- V_bahiab → BAHÍA DE BIZKAIA
- V_bes4 → BESÓS 4

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[4] Offered sales are emitted in €/MWh but, in order to harmonize all currency units in this study, it has been converted to $/MWh, with a currency exchange of $1.12/€ (date of currency exchange: May 24th, 2019).

- V_camgi10 → CAMPO DE GIBRALTAR 10
- V_sagu1 → SAGUNTO 1
- V_sri4r → SOTO 4
- V_sri5 → SOTO DE RIBERA 5
- V_tapower → TARRAGONA POWER

5.8.2 Plotting the arrays

These arrays are plotted together to see how similar or different the shapes of the offer curves of the different units selected are.

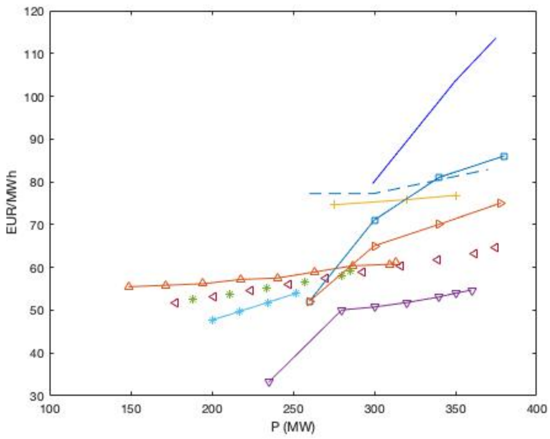

Fig. 5.8.1 Combined cycle units offer curves

To harmonize these slopes, an equivalent curve for the set of curves is calculated to work with only one curve which will serve as the reference offer curve for the combined cycle technology in general.

5.8.3 Slope calculation for each unit

As the arrays do not describe linear functions (see Fig. 5.8.1), the easiest way to calculate the slope of each curve is by calculating the slope of each section of the curve (from point to point). First and last points of each curve have been neglected for these calculations. The way to calculate the slope is the following:

$$m_{j_i} = \frac{(Price_{j_{i+1}} - Price_{j_i})}{(P_{j_{i+1}} - P_{j_i})} \quad (13)$$

being $Price_{j_i}$ the price i of combined cycle unit j and P_{j_i} the offered power i of combined cycle unit j. After these calculations, the slopes of each section of every combined cycle unit curve are stored in individual arrays of only one column.

The next step is to make a weighted average of slopes of each section of the curves to obtain an average slope for each unit. To do so, the following equation is applied, neglecting again the first and last terms of one-column arrays.

$$Weighted\ Average = \frac{(P_{j_{i+1}} - P_{j_i})}{(P_{j_{end}} - P_{j_1})} \tag{14}$$

What the weight average does is to give more importance to those sections that cover larger amounts of MW. Finally, the average slope for each unit is obtained by multiplying the weighted average array by the slope array (element by element) and summing up these products. Once that the average slope for each unit has been calculated, the origin of the function, n_j, is obtained by substituting an arbitrary point of each combined cycle array and its average slope in the following equation:

$$Price_j = m_j \cdot P_j + n_j \tag{15}$$

which is the general offer curve expression of a combined cycle unit j.

5.8.4 Calculation of offer curve of the equivalent combined cycle unit

According to eq. 11, power provided by unit j can be expressed as

$$P_j = \frac{Price_j - n_j}{m_j}$$

so total power of combined cycle units together is $P_t = \sum_j P_j$. As the equivalent combined cycle unit sets a unique price, then $Price_j$ will be equal for all units, so total power can be rewritten as:

$$P_t = \sum_j \frac{Price_j - n_j}{m_j} = \sum_j \frac{Price_j}{m_j} - \frac{n_j}{m_j} = k_t \cdot Price_t - b_t \qquad \text{being} \begin{cases} k_t = \sum_j \frac{j}{m_j} \\ b_t = \sum_j \frac{n_j}{m_j} \end{cases} \tag{16}$$

Rewriting the equation, the following expression for price is obtained:

$$Price_t = m_t \cdot P_t + n_t \qquad \text{being} \begin{cases} m_t = \frac{1}{k_t} \\ n_t = \frac{b_t}{k_t} \end{cases} \tag{17}$$

With this equation, the price of energy set by the 11 units together is obtained. To use the equation to calculate the price of energy for all units needed to cover the thermal demand, factor m_t must be scaled, since it has to be smaller when P_t is larger to obtain a similar price for the energy. In order to scale it, a relation between the capacity of the 11 units considered and the capacity installed to cover the thermal demand is established:

$$m_t = \frac{Capacity_{11\ units}}{Capacity_{thermal\ demand}} \cdot m_t(previous\ value)$$

5.8.5 Hourly price of energy when combined cycle is the only conventional technology

Once m_t and n_t are scaled, a price for each power demanded can be obtained. Since the price of energy is the marginal cost of combined cycle units that enter in the generation mix, the price of energy in the market can be obtained, and it is different for every hour (since the power demanded is different every hour).

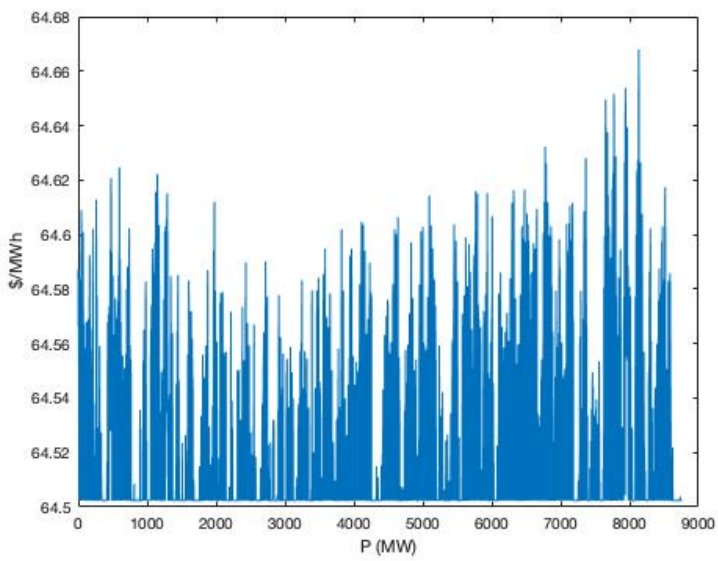

Fig. 5.8.2 Hourly price of energy in 2030

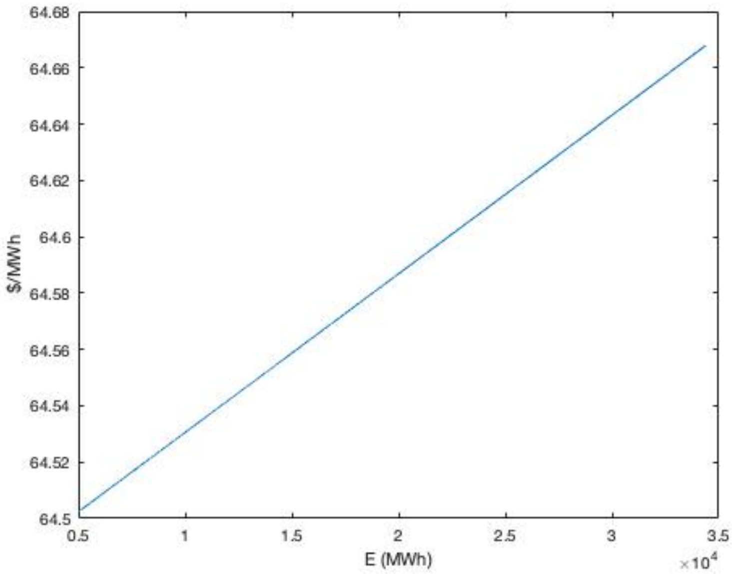

Fig. 5.8.3 Price of energy depending on energy demanded.

5.8.6 Generators' remuneration and costs of the system

To calculate what generators will get from their electricity generated, the vector containing the price of electricity depending on the electricity demanded (Fig. 5.8.3) is multiplied, element by element, by the vector containing the yearly energy generation.

Total costs of the system are calculated with the LCOEs of all technologies in the mix, as explained before. The difference between total costs and generators' remuneration is the so-called "payments by capacity mechanisms", which is what the government must pay to generators for them to be able to cover all their costs.

6. RESULTS

Results of different scenarios are presented and commented below. Installed capacities and energy balances data has been taken from E·SIOS, the official webpage of REE where all generation and consumption data from different technologies is broken down and available to download. Average cost of electricity of base scenarios do not vary no matter what the study case is.

In 2014, total installed capacity in the Spanish Peninsula was 102,262 MW, being combined cycle technology the one with more capacity installed, 24,348 MW, which represents a 25 % of total installed capacity, followed by wind and hydraulic energy technologies, with 22,845 and 19,896 MW of capacity installed, respectively.

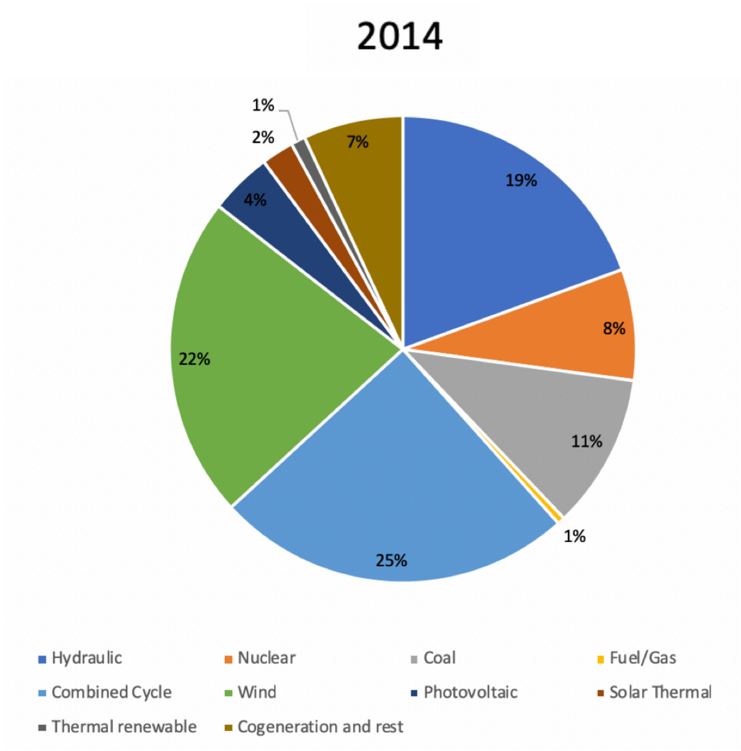

Fig. 5.8.1 Installed capacity shares in 2014

Renewable technologies represent 48 % total capacity installed, being wind energy the one with a largest share. Hydraulic energy is the second most important one, followed by photovoltaic technologies, which are very far from the two previously mentioned technologies, with only 4,428 MW installed. Installed capacities of renewable technologies add up to 50,481 MW.

Regarding the electricity balance, total energy generation is the Spanish Peninsula was 254,743.4 GWh, being nuclear units the ones generating the most, 54,781.3 GWh which represents 26 % of the total generation, followed by wind and hydraulic technologies, which generated 50,635.2 GWh and 42,604.2 GWh, respectively.

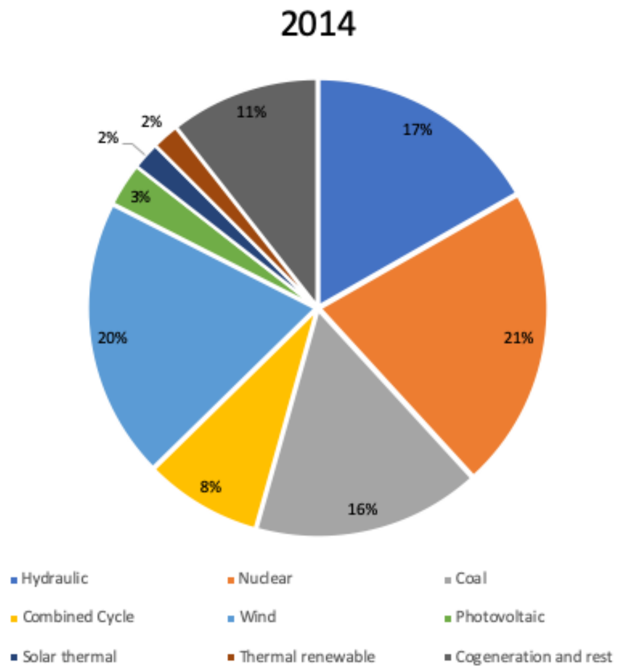

Fig. 5.8.2 Energy generation shares in 2014

Renewable technologies represented 50 % of the total generation, mainly due to the outstanding contribution of wind and hydraulic technologies, which together generated 44 % of the energy.

The average cost of electricity is 69.8 \$/MWh when the interest rate considered is 3 %, 88.9 \$/MWh when interest rate is 5 %, and 105.17 \$/MWh when interest rate is 10 %; the average market price of electricity in 2014 was 61.61 \$/MWh [12]. It is important to highlight that average costs of electricity include both fixed and variable costs while the average market price of electricity only covers, in theory, variable costs.

In 2017, total installed capacity in the Spanish Peninsula was 99,311 MW, being combined cycle technology the one with more capacity installed, 24,948 MW, which supposes an increase of 600 MW with respect to 2014. The other two technologies that have more installed capacity are wind and hydraulic technologies, representing 23 % and 21 %, respectively.

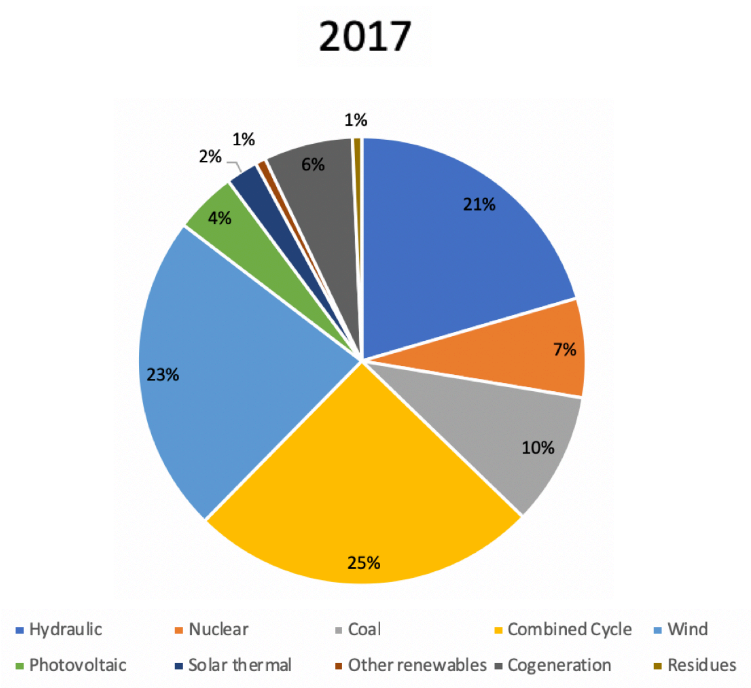

Fig. 5.8.3 Installed capacity shares in 2017

Renewable technologies represent 51 % of total installed capacity (50,667 MW), which implies an increase of 3 % with respect to 2014, although this increase is not due to an increase of installed capacities of renewable technologies but to a decrease of the conventional ones. Wind and hydraulic technologies are the ones with the largest installed capacity by far, followed by photovoltaic technologies, with only 4,431 MW installed, so the situation in 2017 is almost the same as in 2014.

With respect to electricity balance, total energy generation is the Spanish Peninsula was 250,051.1 GWh, being nuclear units the ones generating the most, 55,539.4 GWh, which represents 22 % of the total generation, followed by wind and coal technologies, which generated 47,508.1 GWh and 42,424.3 GWh, respectively. There is a remarkable difference between generation in 2017 and generation in 2014 with respect to the amount of energy generated by each technology. In 2017, as it was a very dry year, hydraulic generation was less than half of its generation in 2014 (only 20,721.6 GWh were generated). Its deficit in generation was mainly covered by combined cycle technologies, which generated about a 50 % more during 2017 (33,648 GWh).

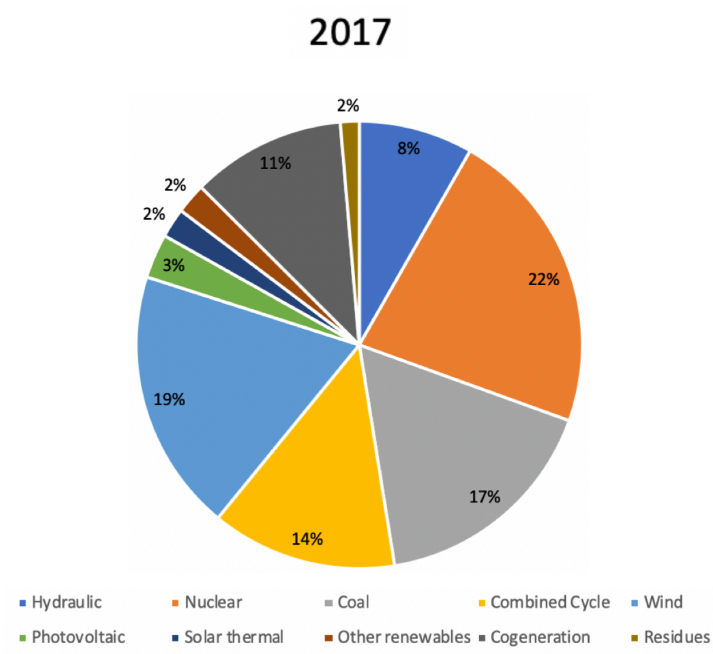

Fig. 5.8.4 Energy generation shares in 2017

Renewable technologies represented 34 % of the total generation, which is a decrease of 16 percentage points with respect to 2014. This is again due to the drastic decrease of hydraulic generation.

The average cost of electricity is 72.17 $/MWh when the interest rate considered is 3 %, 90 $/MWh when interest rate is 5 %, and 106.36 $/MWh when interest rate is 10 %; the average market price of electricity in 2017 was 67.87 $/MWh [13], which was a 25.1 % more than previous year.

There are two things that must be remarked: first, the mismatch between generation a demand in both base scenarios is due to the international interchanges and the link between the Peninsula and the Balearic Islands, that have not been included in the demand. Second, the average price of electricity is calculated according to equation (10), but it does not correspond to real life prices, since it does not consider any taxes, so it is just used as a reference value to see how it fluctuates when the 2030 scenario is stated.

6.1 Study case 1: nuclear, combined cycle and coal as conventional technologies

When values from base scenarios are scaled to 2030, and an 80 % of renewable generation is imposed to total yearly generation, conventional installed capacity shares drop drastically compared to base scenarios values, but total installed capacity increases quite significantly, mainly due to the low capacity factor that renewable technologies have. **When 2014 is the base scenario**, total installed capacity in 2030 is 182,011.9 MW, which is an increase of 79,749.9 MW with respect to its base scenario. Conventional technologies only represent 16 % of the total installed capacity, being coal technologies out of the mix no matter what the interest rate is.

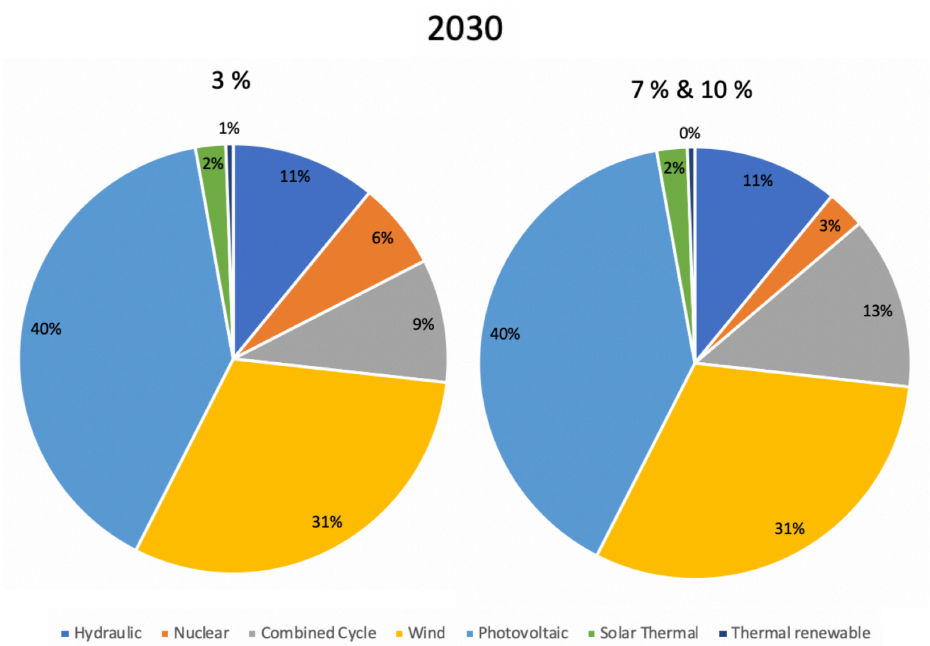

Fig. 6.1.1 Installed capacity shares in 2030 with 2014 as base scenario

When interest rate is 3 %, nuclear technologies represent 6 % of the installed capacity and combined cycle technologies 9 %, although when interest rate increases to 7 % and 10 % combined cycle installed capacity increases up to 13 % to the detriment of nuclear technologies, which have much higher fixed costs. This situation is similar **when 2017 is the base scenario**, having a total installed capacity in 2030 of 202,237.1 MW, which implies an increase of 102,926.1 MW with respect to its base scenario (more than a 100 % of increase). Conventional technologies represent 17 % of total installed capacity, with coal technologies out of the mix in any case, as explained before when base scenario was 2014. When interest rate is 3 %, nuclear technologies represent 6 % of the installed capacity and combined cycle technologies 11 %, although when interest rate increases to 7 % and 10 % combined cycle capacity increases up to 14 %.

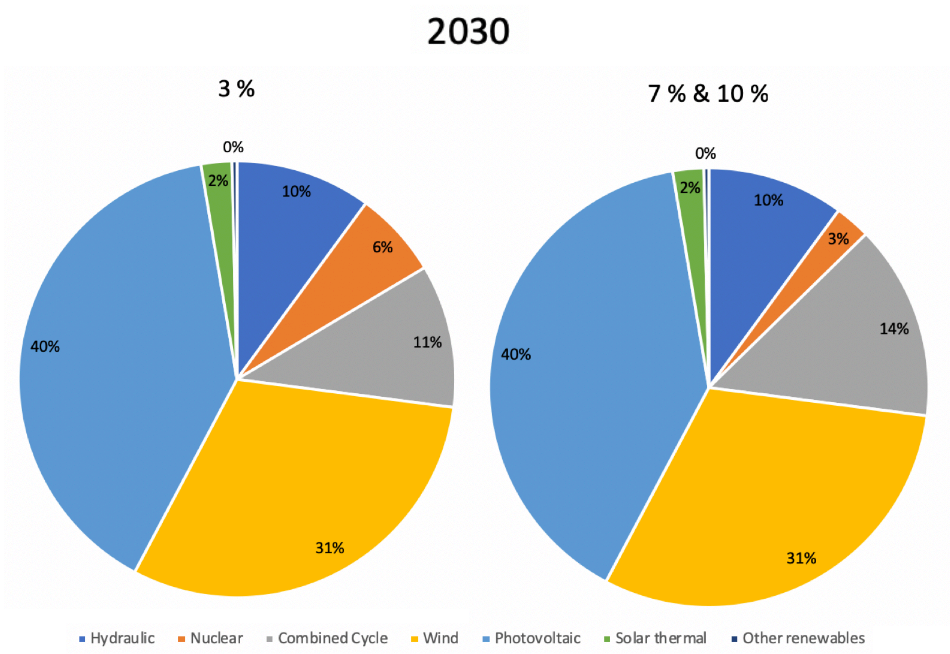

Fig. 6.1.2 Installed capacity shares in 2030 with 2017 as base scenario

The renewable technology with the largest share of installed capacities is photovoltaic, with a 40 %, followed by wind technologies.

Regarding the energy balances, there is a larger mismatch between generation and demand in 2030 than in base scenarios because a minimum of 5 GWh has been imposed and big amounts of energy are wasted. As it has been imposed, renewable technologies generation represent 80 % of the total yearly energy generation. **When 2014 is the base scenario**, generation is 376,387.8 GWh, demand is 284,293.1 GWh and the energy wasted is thereof 92,094.8 GWh. Photovoltaic technologies are the ones generating the most, 126,459.9 GWh, followed by wind and nuclear technologies.

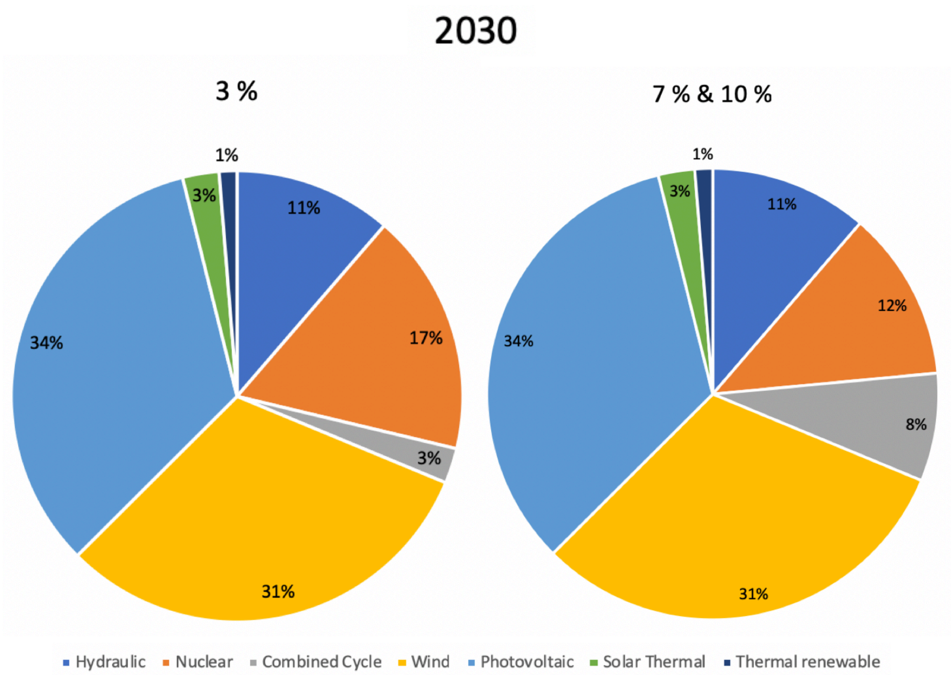

Fig. 6.1.3 Energy generation shares in 2030 with 2014 as base scenario

When the interest rate considered is 3 %, nuclear technologies generate 17 % of the energy and combined cycle 3 %, but when interest rate increases to 7 % or 10 %, this difference in generation gets reduced to 12 % for nuclear technologies and 8 % for combined cycle. This gap between nuclear and combined cycle generations is even larger **if base scenario is 2017**, being 18 % for nuclear and 2 % for combined cycle technologies when interest rate is 3 %, and 12 % and 8 % when interest rates are 7 % and 10 %.

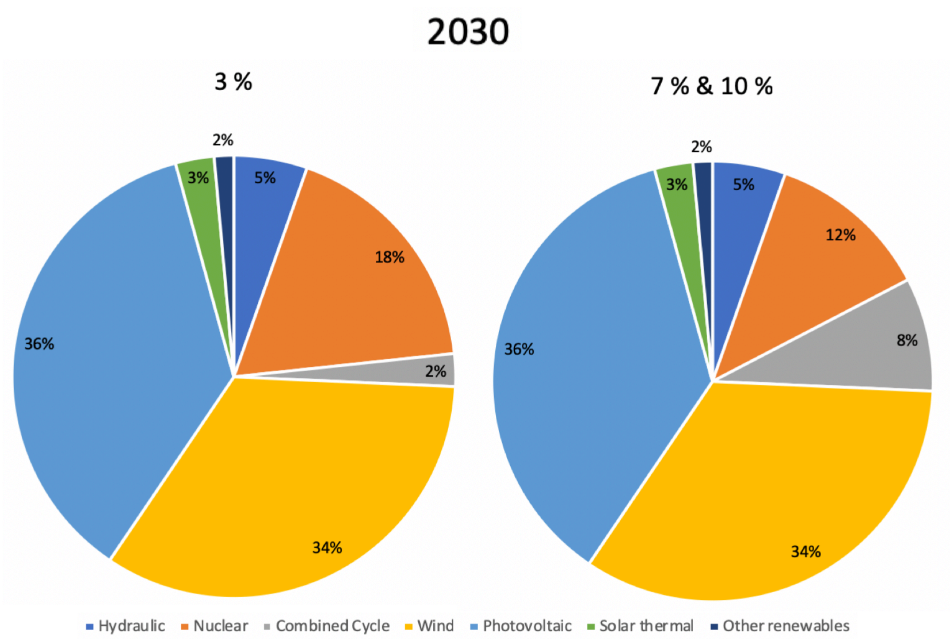

Fig. 6.1.4 Energy generation shares in 2030 with 2017 as base scenario

Generation in 2030 when base scenario is 2017 is 386,591.1 GWh, which is a larger value than the one obtained when base scenarios is 2014, and the same thing happens with demand, which is 285,152.6 GWh, leading to an energy waste of 101,438.5 GWh. Photovoltaic technologies are again the ones generating the most, with 140,303.4 GWh, followed by wind (130,531.6 GWh) and combined cycle technologies.

An important issue is the number of hours that nuclear technologies, with the thermal park obtained for 2030, operate solely, because it cannot happen in real life since nuclear technologies are not designed to operate following the demand instantaneously but operating at a constant power level, so that fault should be corrected in some way. **When base scenario is 2014** and interest rate is 3 %, nuclear technologies operate 6,789 hours by themselves, while for interest rates of 7 % and 10 %, during 4,977 hours the only technologies operating are the nuclear ones. This situation is almost the same **when base scenario is 2017**, with nuclear technologies operating solely for 6,814 hours when interest rate is 3 % and 4,874 hours when interest rates are 7 % and 10 %.

Finally, the average cost of electricity is analyzed and compared to base scenario values. In both cases, the average cost of electricity is significantly higher in 2030, and it increases as interest rate increases. **When 2014 is the base scenario**, average cost of electricity is 85.17 $/MWh for an interest rate of 3 %, 113.76 $/MWh for an interest rate of 7 %, and 135.15 for an interest rate of 10 %. **In the case of 2017 being the base scenario**, average cost of electricity is 87.16 $/MWh for an interest rate of 3 %, 116.25 $/MWh for an interest rate of 7 %, and 138.52 $/MWh for an interest rate of 10 %.

6.1.1 Base year: 2014

TABLE 6.1.1 INSTALLED CAPACITY (MW)

TECHNOLOGY	2014 (1)	2030		
		3 %	7 %	10 %
Hydraulic	19,896.0	19,896.0	19,896.0	19,896.0
Nuclear	**7,866.0**	**11,904.5**	**5.238,1**	**5.238,1**
Coal	**10,972.0**	**-**	**-**	**-**
Fuel/Gas	520	-	-	-
Combined Cycle	**25,348.0**	**16,904.1**	**23,570.5**	**23,570.5**
Wind	22,845.0	55,960.9	55,960.9	55,960.9
Photovoltaic	4,428.0	72,180.3	72,180.3	72,180.3
Solar thermal	2,300.0	4,154.1	4,154.1	4,154.1
Thermal renewable (2)	1,012.0	1,012.0	1,012.0	1,012.0
Cogeneration and rest (3)	7,075.0	-	-	-
Total	**102,262.0**	**182,011.9**	**182,011.9**	**182,011.9**

Source: self-made

(1) Data taken from ESIOS.
(2) Includes biogas, biomass, and geothermal.
(3) Includes cogeneration and residues.

TABLE 6.1.2 ENERGY BALANCE (GWh)

TECHNOLOGY	2014 [1]	2030		
		3 %	7 %	10 %
Hydraulic	42,604.2	42,604.2	42,604.2	42,604.2
Nuclear	**54,781.3**	**65,538.4**	**45,885.6**	**45,885.6**
Coal	**41,064.4**	**-**	**-**	**-**
Fuel/Gas	-	-	-	-
Combined Cycle	**21,120.5**	**9,501.1**	**29,153.9**	**29,153.9**
Wind	50,635.2	117,652.2	117,652.2	117,652.2
Photovoltaic	7,802.4	126,459.9	126,459.9	126,459.9
Solar thermal	4,958.9	9,825.2	9,825.2	9,825.2
Thermal renewable [2]	4,806.8	4,806.8	4,806.8	4,806.8
Cogeneration and rest [3]	26,970.5	-	-	-
Generation	**254,743.4**	**376,387.8**	**376,387.8**	**376,387.8**
Demand [4]	**248,541.5**	**284,293.1**	**284,293.1**	**284,293.1**
Generation - Demand	**6,201.9**	**92,094.8**	**92,094.8**	**92,094.8**

Source: self-made

(1) Date taken from ESIOS.
(2) Includes biogas, biomass, and geothermal.
(3) Includes cogeneration and residues.
(4) Energy demand at generator terminals minus Pumping consumption.

TABLE 6.1.3 HOURS WHEN NUCLEAR IS THE ONLY CONVENTIONAL TECHNOLOGY IN 2030

	3 %	7 %	10 %
Hours	6,789	4,977	4,977

Source: self-made

TABLE 6.1.4 AVERAGE COST OF ELECTRICITY ($/MWh)

2014			2030		
3 %	7 %	10 %	3 %	7 %	10 %
69.80	88.99	105.17	85.17	113.76	135.15

Source: self-made

6.1.2 Base year: 2017

TABLE 6.1.5 INSTALLED CAPACITY (MW)

TECHNOLOGY	2017 [1]	2030		
		3 %	7 %	10 %
Hydraulic	20,331.0	20,331.0	20,331.0	20,331.0

Nuclear	**7,117.0**	**12,935.2**	**5,293.9**	**5,293.9**
Coal	**9,536.0**	**-**	**-**	**-**
Fuel/Gas	-	-	-	-
Combined Cycle	**24,948.0**	**21,454.4**	**29,095.6**	**29,095.6**
Wind	22,863.0	62,086.9	62,086.9	62,086.9
Photovoltaic	4,431.0	80,081.9	80,081.9	80,081.9
Solar thermal	2,299.0	4,608.8	4,608.8	4,608.8
Other renewables (2)	743.0	743.0	743.0	743.0
Cogeneration	6,373.0	-	-	-
Residues	670.0	-	-	-
Total	**99,311.0**	**202,237.1**	**202,237.1**	**202,237.1**

Source: self-made

(1) Data taken from ESIOS.
(2) Includes biogas, biomass, hydraulic marine, and geothermal.

TABLE 6.1.6 ENERGY BALANCE (GWh)

TECHNOLOGY	2017 (1)	2030		
		3 %	7 %	10 %
Hydraulic	20,721.6	20,721.6	20,721.6	20,721.6
Nuclear	**55,539.4**	**69,418.8**	**46,374.5**	**46,374.5**
Coal	**42,424.3**	**-**	**-**	**-**
Fuel/Gas	-	-	-	-
Combined Cycle	**33,648.0**	**9,210.7**	**32,255.0**	**32,255.0**
Wind	47,508.1	130,531.6	130,531.6	130,531.6
Photovoltaic	8,000.3	140,303.4	140,303.4	140,303.4
Solar thermal	5,348.0	10,900.8	10,900.8	10,900.8
Other renewables (2)	5,504.2	5,504.2	5,504.2	5,504.2
Cogeneration	27,947.0	-	-	-
Residues	3,410.2	-	-	-
Generation	**250,051.1**	**386,591.1**	**386,591.1**	**386,591.1**
Demand (3)	**256,083.9**	**285,152.6**	**285,152.6**	**285,152.6**
Generation - Demand	**-6,032.8**	**101,439.1**	**101,439.1**	**101,439.1**

Source: self-made

(1) Date taken from ESIOS.
(2) Includes biogas, biomass, hydraulic marine, and geothermal.
(3) Energy demand at generator terminals minus Pumping consumption.

Table 6.1.7 HOURS WHEN NUCLEAR IS THE ONLY CONVENTIONAL TECHNOLOGY

	3 %	7 %	10 %
Hours	6,814	4,874	4,874

Source: self-made

TABLE 6.1.8 AVERAGE COST OF ELECTRICITY ($/MWh)

2017			2030		
3 %	7 %	10 %	3 %	7 %	10 %
72.17	90.00	106.36	87.16	116.25	138.52

Source: self-made

6.2 Study case 2: nuclear technologies out of the mix

In this section, the fixed costs that would make nuclear technology economically suboptimal to be present in the generation mix are calculated. Unlike other technologies, costs of nuclear technology may differ a lot depending on the source where they are published [14].

For this project, nuclear costs are taken from *Energy Technology Perspectives 2010* [16]. The investment and fixed costs of nuclear technology when they are not modified to take nuclear out of the generation mix are:

- $CV = 12\ \$/MWh$
- $CI = 3{,}000\ \$/kW$
- $CF = \begin{cases} 3\ \% \rightarrow 12.37 \\ 7\ \% \rightarrow 24.39 \\ 10\ \% \rightarrow 34.36 \end{cases} \quad \$/MWh$

Independently on the base scenario chosen, the behavior of nuclear technologies to changes on their investment costs and fixed costs is the same with respect to their entrance or exit of the generation mix. It is important to highlight that the parameter that has been manipulated is the investment cost, since fixed cost just a calculation that comes from it. When interest rate is considered to be 3 %, the investment cost that would push nuclear out of the generation mix is 6,388 \$/kW, which is more than two times larger than the actual value. If interest rate is 7 %, investment cost should be at least 4,355 \$/kW for nuclear technology to be economically suboptimal to be part of the mix, and if interest rate is 10 %, the investment cost that would push nuclear out of the generation mix is 3,771 \$/kW, which is a relatively close value to the actual one.

Total installed capacity in 2030 is the same as in the previous study case for each base scenario, the only difference is the installed capacities of conventional technologies. **When base scenario is 2014**, 7,142.8 MW of coal technologies are installed if interest rate is 3 %, which represents a 4 % of total installed capacity, but if interest rate is 7 % or 10 %, its share is even smaller (just a 3 %). On the other hand, combined cycle technologies have much more installed capacity, with 21,665.8 MW if the interest rate is 3 %, and 23,570.5 MW if interest rate is 7 % or 10 %, which represents the 13 % of total capacity installed.

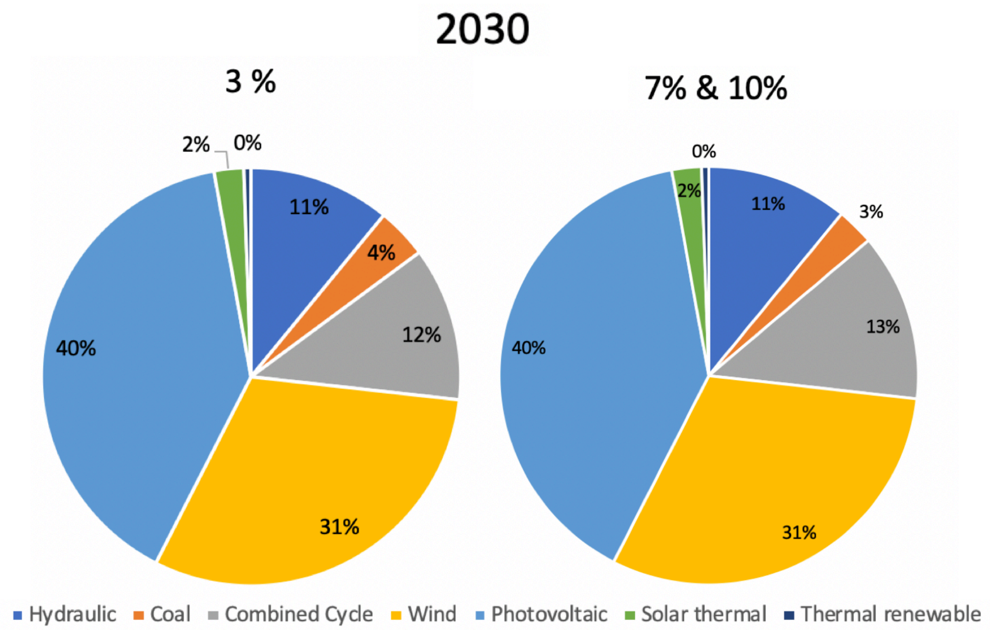

Fig. 6.2.1 Installed capacity shares in 2030 with 2014 as base scenario

A similar situation occurs **when 2017 is the base scenario**. With an interest rate of 3 %, installed capacity of coal and combined cycle technologies are 7,393 MW and 26,450.6 MW, respectively. For interest rates of 7 % or 10 %, the difference between their installed capacities gets even larger, with 5,293.9 MW for coal technologies and 29,095.6 MW for combined cycle technologies, which represent 3 % and 14 % of total installed capacity, respectively.

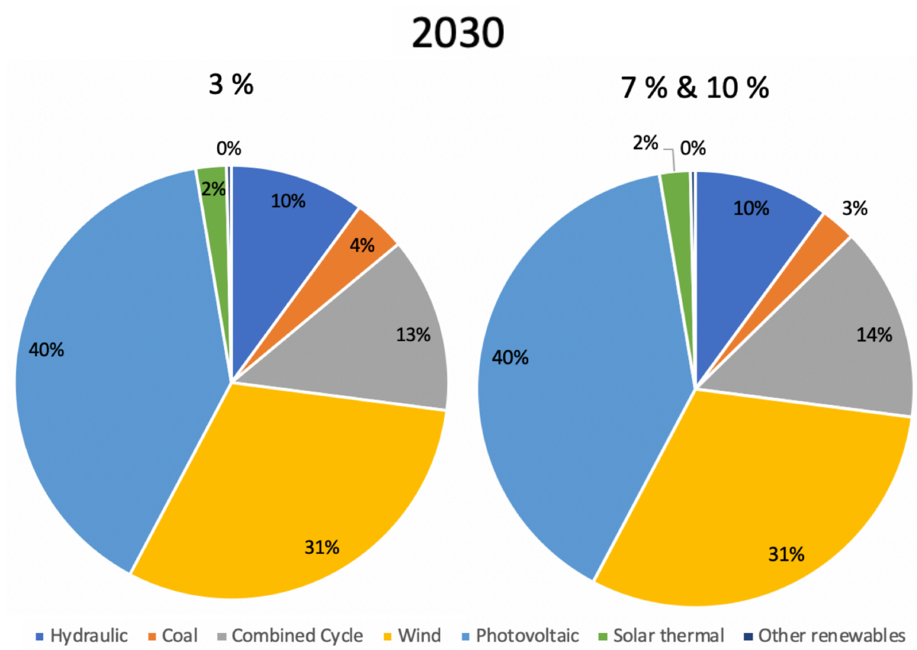

Fig. 6.2.2 Installed capacity shares in 2030 with 2017 as base scenario

Regarding energy generation, the conventional technology that generates the most with either base scenario is coal, but as interest rate increases its generation decreases in favor of combined cycle technologies. **If base scenario is 2014**, coal technologies generate 52,693.7 GWh when interest rate is 3 %, which is a 14 % of the total energy generation. For interest rates of 7 % and 10 %, these technologies generate 45,885.6 GWh, which represents 12 % of total generation.

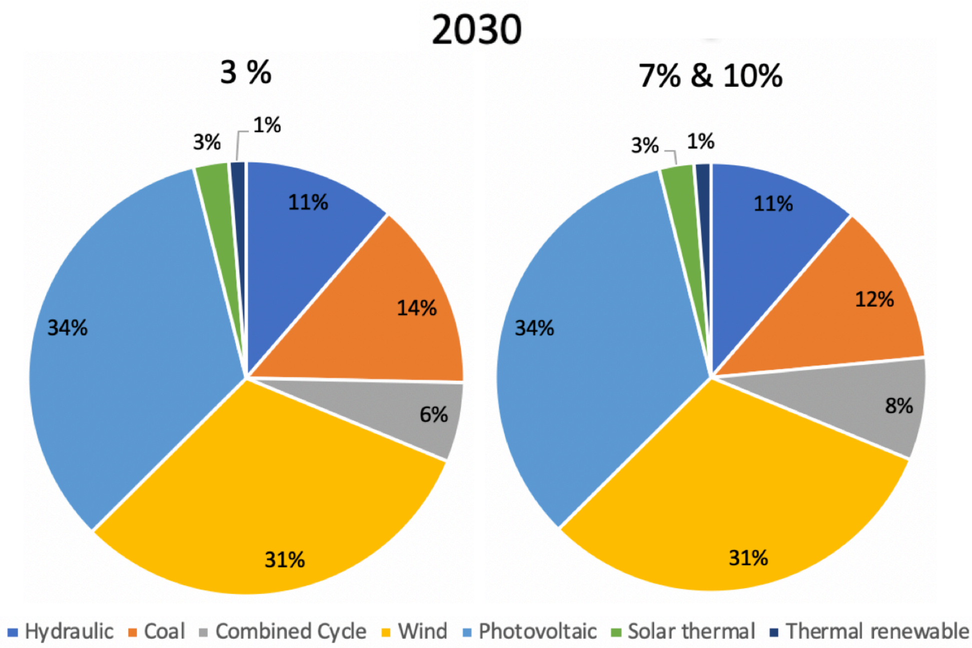

Fig. 6.2.3 Energy generation shares in 2030 with 2014 as base scenario

On the other hand, combined cycle technologies generate 22,345.8 GWh when interest rate is 3 % and 29,153.9 GWh when interest rates are 7 % or 10 %. **If base scenario is 2017**, coal technologies generate 55,960.8 GWh and combined cycle technologies 22,668.7 GWh when interest rate is 3 %, and 46,374.5 GWh and 32,255 GWh when interest rate is 7 % or 10 %, which represent 12 % and 8 % of total energy generated, respectively.

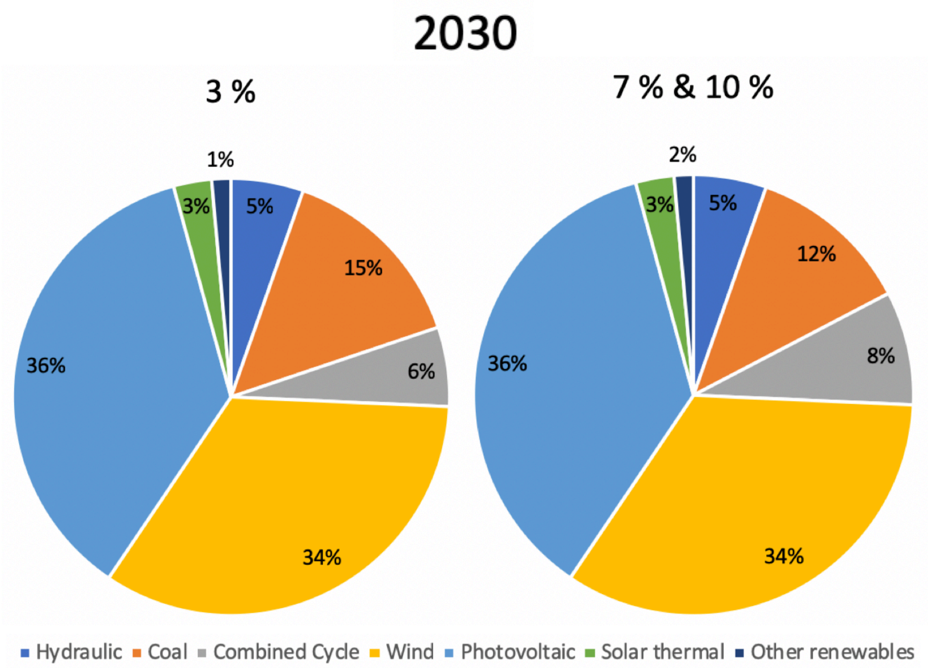

Fig. 6.2.4 Energy generation shares in 2030 with 2017 as base scenario

Finally, the average cost of electricity is calculated. **Considering 2014 as base scenario**, if interest rate is 3 % the average electricity cost is 90.98 $/MWh, 114.69 $/MWh if interest rate is 7 %, and 133.8 $/MWh if interest rate is 10 %. **With 2017 as base scenario**, average electricity costs are slightly higher, being 93.13 $/MWh if interest rate is 3 %, 117.17 $/MWh if interest rate is 7 %, and 137.19 $/MWh if interest rate is 10 %.

6.2.1 Base year: 2014

TABLE 6.2.1 INVESTMENT AND FIXED COSTS THAT EXISTS NUCLEAR FROM THE MIX

	REAL VALUES			VALUES THAT WOULD TAKE NUCLEAR OUT OF THE MIX IN 2030		
	3 %	7 %	10 %	3 %	7 %	10 %
Investment Cost ($/kW)	3,000			6,388	4,355	3,771
Fixed Cost ($/MWh)	12.37	24.39	34.36	26.35	35.41	43.18

Source: self-made

TABLE 6.2.2 INSTALLED CAPACITY (MW)

TECHNOLOGY	2014 (1)	2030		
		3 %	7 %	10 %
Hydraulic	19,896.0	19,896.0	19,896.0	19,896.0
Nuclear	**7,866.0**	**-**	**-**	**-**

Coal	**10,972.0**	**7,142.8**	**5,238.1**	**5,238.1**
Fuel/Gas	520	-	-	-
Combined Cycle	**25,348.0**	**21,665.8**	**23,570.5**	**23,570.5**
Wind	22,845.0	55,960.9	55,960.9	55,960.9
Photovoltaic	4,428.0	72,180.3	72,180.3	72,180.3
Solar thermal	2,300.0	4,154.1	4,154.1	4,154.1
Thermal renewable (2)	1,012.0	1,012.0	1,012.0	1,012.0
Cogeneration and rest (3)	7,075.0	-	-	-
Total	**102,262.0**	**182,011.9**	**182,011.9**	**182,011.9**

Source: self-made

(1) Data taken from ESIOS.
(2) Includes biogas, biomass, and geothermal.
(3) Includes cogeneration and residues.

TABLE 6.2.3 ENERGY BALANCE (GWh)

TECHNOLOGY	2014 (1)	2030		
		3 %	7 %	10 %
Hydraulic	42,604.2	42,604.2	42,604.2	42,604.2
Nuclear	**54,781.3**	**-**	**-**	**-**
Coal	**41,064.4**	**52,693.7**	**45,885.6**	**45,885.6**
Fuel/Gas	-	-	-	-
Combined Cycle	**21,120.5**	**22,345.8**	**29,153.9**	**29,153.9**
Wind	50,635.2	117,652.2	117,652.2	117,652.2
Photovoltaic	7,802.4	126,459.9	126,459.9	126,459.9
Solar thermal	4,958.9	9,825.2	9,825.2	9,825.2
Thermal renewable (2)	4,806.8	4,806.8	4,806.8	4,806.8
Cogeneration and rest (3)	26,970.5	-	-	-
Generation	**254,743.4**	**376,387.8**	**376,387.8**	**376,387.8**
Demand (4)	**248,541.5**	**284,293.1**	**284,293.1**	**284,293.1**
Generation - Demand	**6,201.9**	**92,094.8**	**92,094.8**	**92,094.8**

Source: self-made

(1) Date taken from ESIOS.
(2) Includes biogas, biomass, and geothermal.
(3) Includes cogeneration and residues.
(4) Energy demand at generator terminals minus Pumping consumption.

TABLE 6.2.4 AVERAGE COST OF ELECTRICITY ($/MWh)

2014			2030		
3 %	7 %	10 %	3 %	7 %	10 %
69.80	88.99	105.17	90.98	114.69	133.80

Source: self-made

6.2.2 Base year: 2017

TABLE 6.2.5 INVESTMENT AND FIXED COSTS THAT EXITS NUCLEAR FROM THE MIX

	REAL VALUES			VALUES THAT WOULD TAKE NUCLEAR OUT OF THE MIX IN 2030		
	3 %	7 %	10 %	3 %	7 %	10 %
Investment Cost ($/kW)	3,000			6,388	4,355	3,771
Fixed Cost ($/MWh)	12.37	24.39	34.36	26.35	35.41	43.18

Source: self-made

TABLE 6.2.6 INSTALLED CAPACITY (MW)

TECHNOLOGY	2017 (1)	2030		
		3 %	7 %	10 %
Hydraulic	20,331.0	20,331.0	20,331.0	20,331.0
Nuclear	**7,117.0**	**-**	**-**	**-**
Coal	**9,536.0**	**7,939.0**	**5,293.9**	**5,293.9**
Fuel/Gas	-	-	-	-
Combined Cycle	**24,948.0**	**26,450.6**	**29,095.6**	**29,095.6**
Wind	22,863.0	62,086.9	62,086.9	62,086.9
Photovoltaic	4,431.0	80,081.9	80,081.9	80,081.9
Solar thermal	2,299.0	4,608.8	4,608.8	4,608.8
Other renewables (2)	743.0	743.0	743.0	743.0
Cogeneration	6,373.0	-	-	-
Residues	670.0	-	-	-
Total	**99,311.0**	**202,237.1**	**202,237.1**	**202,237.1**

Source: self-made

(1) Data taken from ESIOS.
(2) Includes biogas, biomass, hydraulic marine, and geothermal.

TABLE 6.2.7 ENERGY BALANCE (GWh)

TECHNOLOGY	2017 (1)	2030		
		3 %	7 %	10 %
Hydraulic	20,721.6	20,721.6	20,721.6	20,721.6
Nuclear	**55,539.4**	**-**	**-**	**-**
Coal	**42,424.3**	**55,960.8**	**46,374.5**	**46,374.5**
Fuel/Gas	-	-	-	-
Combined Cycle	**33,648.0**	**22,668.7**	**32,255.0**	**32,255.0**
Wind	47,508.1	130,531.6	130,531.6	130,531.6
Photovoltaic	8,000.3	140,303.4	140,303.4	140,303.4
Solar thermal	5,348.0	10,900.8	10,900.8	10,900.8
Other renewables (2)	5,504.2	5,504.2	5,504.2	5,504.2
Cogeneration	27,947.0	-	-	-
Residues	3,410.2	-	-	-
Generation	**250,051.1**	**386,591.1**	**386,591.1**	**386,591.1**
Demand (3)	**256,083.9**	**285,152.6**	**285,152.6**	**285,152.6**
Generation - Demand	**-6,032.8**	**101,439.1**	**101,439.1**	**101,439.1**

Source: self-made

(1) Date taken from ESIOS.

(2) Includes biogas, biomass, hydraulic marine, and geothermal.
[3] Energy demand at generator terminals minus Pumping consumption.

TABLE 6.2.8 AVERAGE COST OF ELECTRICITY ($/MWh)

2017			2030		
3 %	**7 %**	**10 %**	**3 %**	**7 %**	**10 %**
72.17	90.00	106.36	93.13	117.17	137.19

Source: self-made

6.3 Study case 3: combined cycle as the only conventional technology

In this case, combined cycle is the only conventional technology operating to cover the thermal demand. For that reason, installed capacity of combined cycle technology is larger compared with the two previous scenarios, since there is no nuclear or coal units installed at all. Its installed capacity share in 2030, **with 2014 as base scenario**, is 16 %, making it the third most important technology behind photovoltaic and wind technologies, representing the 40 % and 31 % of the total share, respectively.

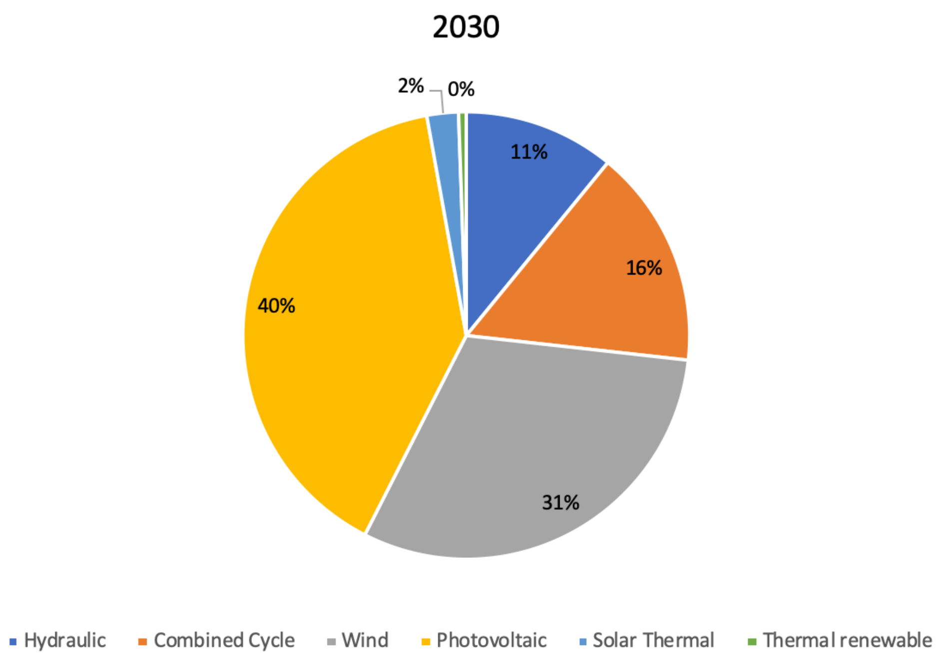

Fig. 6.3.1 Installed capacity shares in 2030 with 2014 as base scenario

When 2017 is used as base scenario, installed capacity in 2030 is 17 %, being photovoltaic and wind the two most important technologies again.

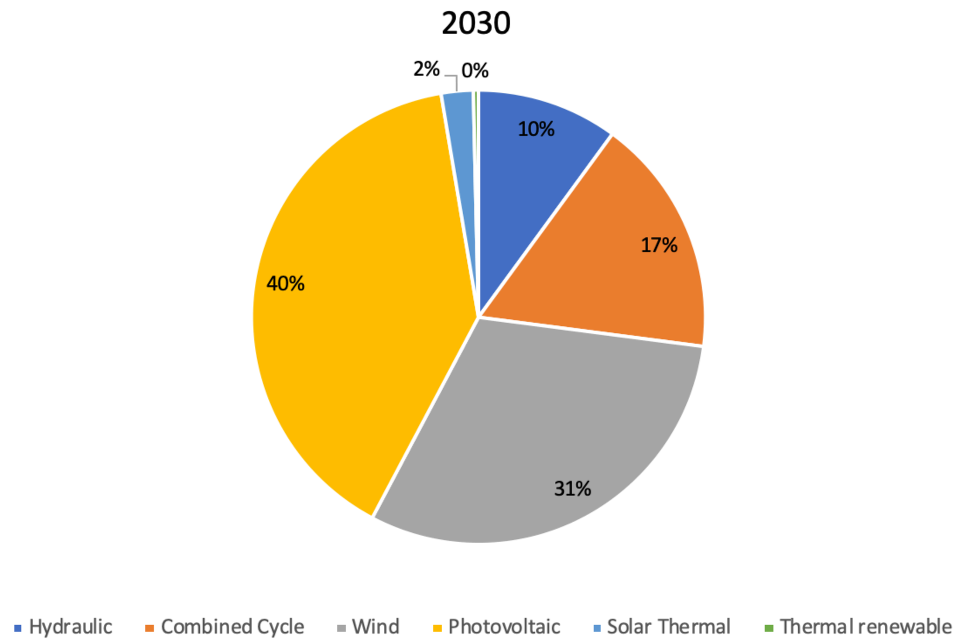

Fig. 6.3.2 Installed capacity shares in 2030 with 2017 as base scenario

Regarding the energy balance, as renewable technologies were set to cover the 80 % of the total energy production in 2030, combined cycle generation units cover the remaining 20 %, since they are the only units representing conventional technologies in the mix. **When base scenario is 2014**, combined cycle units generate 75,039.5 GWh in 2030, being the third technology that generates the most. **In case of 2017 being the base scenario**, combined cycle units generate 78,629.5 GWh.

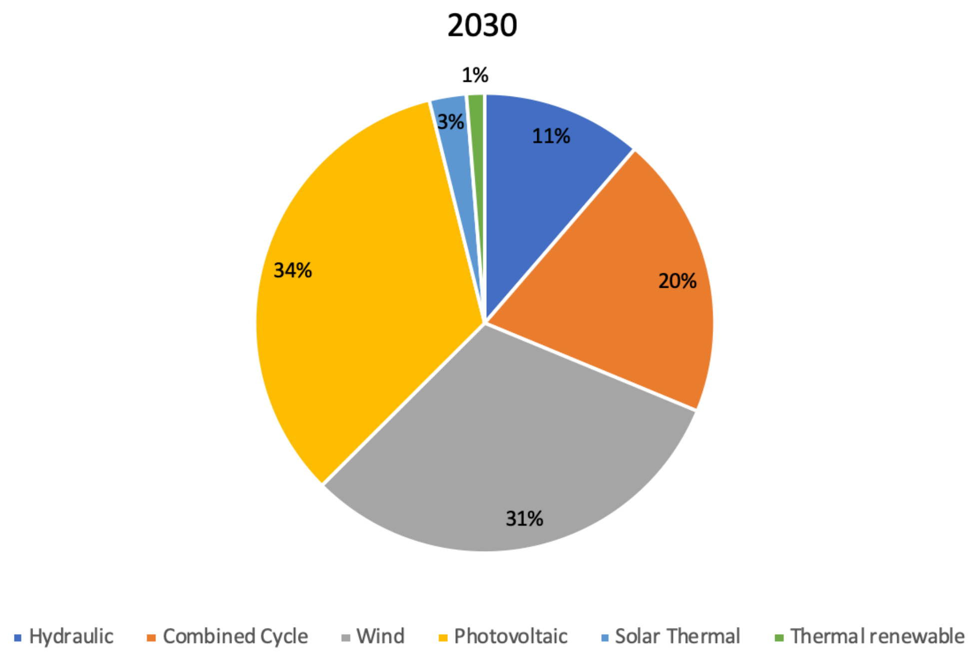

Fig. 6.3.3 Energy generation shares in 2030 with 2014 as base scenario

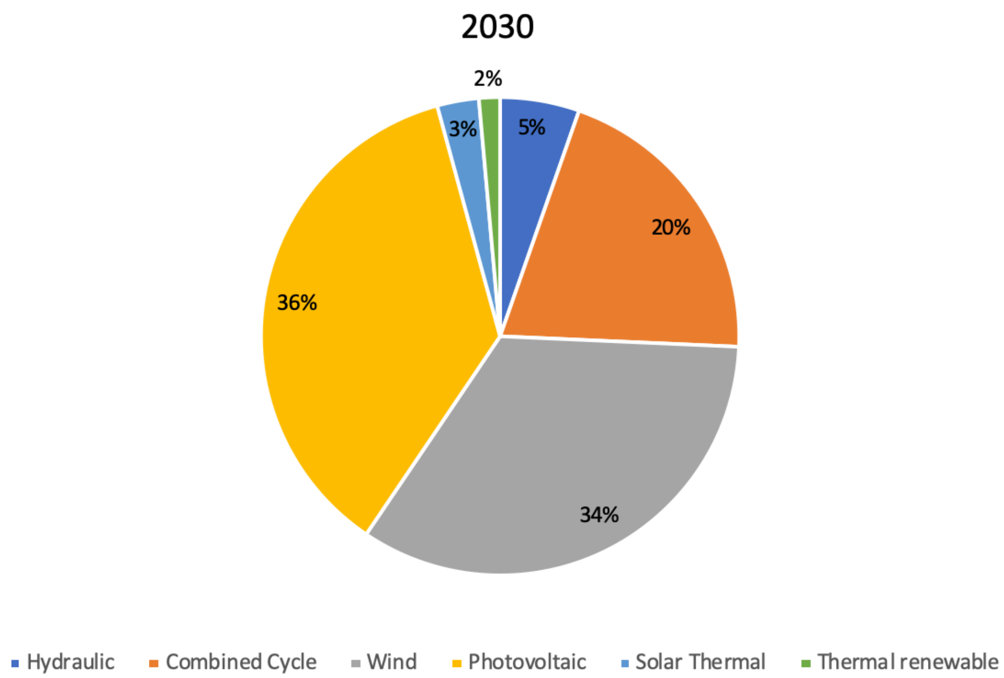

Fig. 6.3.4 Energy generation shares in 2030 with 2017 as base scenario

The price of electricity oscillates between 64.50 $/MWh and 64.67 $/MWh depending on the amount of energy demanded, which implies a different price of electricity for every hour.

Total costs of the system vary significantly depending on the base scenario used and the interest rate considered. **When 2014 is used as base scenario**, considering an interest rate of 3 %, total costs in 2014 were 17.78 billion $, while in 2030 they will be 36.1 billion $. For an interest rate of 5 %, total costs in 2014 were 22.67 billion $, while in 2030 they will be 46.69 billion $. Finally, considering an interest rate of 10 %, total costs in 2014 were 26.79 billion $, while in 2030 they will be 51.63 billion $. Remuneration for generators in 2030 is considered to be the same no matter what the interest rate is, having a value of 24.18 billion $, which leads to a deficit in incomes of the generators of 11.92 billion $ when interest rate is 3 %, 20.41 billion $ when interest rate is 5 % and, 27.45 $ when interest rate is 10 %. For the case **when 2017 is the base scenario**, if 3 % is set as the interest rate, costs in total costs of the system in 2017 were 18.05 billion $, while in 2030 they will be 37.95 billion $. Considering an interest rate of 5 %, total costs of the system in 2017 were 22.51 billion $, while in 2030 they will be 46.69 billion $. Finally, when interest rate is 10 %, total costs of the system in 2017 were 26.6 billion $, while in 2030 they will be 54.28 $. Remuneration for generators in 2030 is 24.81 billion $, leading to a deficit in incomes of generators of 13.14 billion $ for an interest rate of 3 %, 21.88

billion $ when interest rate is 5 %, and 29.47 billion $ being 10 % the interest rate. This deficit in incomes that generators suffer is accounted by the government as payment by capacity mechanisms, which must be paid to generators to cover all their costs.

6.3.1 Base scenario: 2014

TABLE 6.3.1 INSTALLED CAPACITY (MW)

TECHNOLOGY	2014 (1)	2030
Hydraulic	19,896.0	19,896.0
Nuclear	**7,866.0**	**-**
Coal	**10,972.0**	**-**
Fuel/Gas	520.0	-
Combined Cycle	**25,348.0**	**28,808.6**
Wind	22,845.0	55,960.9
Photovoltaic	4,428.0	72,180.3
Solar thermal	2,300.0	4,154.1
Thermal renewable (2)	1,012.0	1,012.0
Cogeneration and rest (3)	7,075.0	-
Total	**102,262.0**	**182,011.9**

Source: self-made

(1) Data taken from ESIOS.
(2) Includes biogas, biomass, and geothermal.
(3) Includes cogeneration and residues.

TABLE 6.3.2 ENERGY BALANCE (GWh)

TECHNOLOGY	2014 (1)	2030
Hydraulic	42,604.2	42,604.2
Nuclear	**54,781.3**	**-**
Coal	**41,064.4**	**-**
Fuel/Gas	-	-
Combined Cycle	**21,120.5**	**75,039.5**
Wind	50,635.2	117,652.2
Photovoltaic	7,802.4	126,459.9
Solar thermal	4,958.9	9,825.2
Thermal renewable (2)	4,806.8	4,806.8
Cogeneration and rest (3)	26,970.5	-
Generation	**254,743.4**	**376,387.8**
Demand (4)	**248,541.5**	**284,293.1**
Generation - Demand	**6,201.9**	**92,094.8**

Source: self-made

(1) Date taken from ESIOS.
(2) Includes biogas, biomass, and geothermal.
(3) Includes cogeneration and residues.
(4) Energy demand at generator terminals minus Pumping consumption.

TABLE 6.3.3 COSTS OF THE SYSTEM, REMUNERATION, CAPACITY PAYMENTS

	2014			2030		
	3 %	7 %	10 %	3 %	7 %	10 %
Costs of the system (billion $)	17.78	22.67	26.79	36.10	44.59	51.63
Remuneration of generators (billion $)				24.18		
Payment by capacity mechanisms (1) (billion $)				11.92	20.41	27.45

Source: self-made

(1) Costs of the System minus Payment by capacity mechanisms.

6.3.2 Base scenario: 2017

TABLE 6.3.4 INSTALLED CAPACITY (MW)

TECHNOLOGY	2017 (1)	2030
Hydraulic	20,331.0	20,331.0
Nuclear	**7,117.0**	**-**
Coal	**9,536.0**	**-**
Fuel/Gas	-	-
Combined Cycle	**24,948.0**	**34,389.5**
Wind	22,863.0	62,086.9
Photovoltaic	4,431.0	80,081.9
Solar thermal	2,299.0	4,608.8
Other renewables (2)	743.0	743.0
Cogeneration	6,373.0	-
Residues	670.0	-
Total	**99,311.0**	**202,237.1**

Source: self-made

(1) Data taken from "El Sistema eléctrico español (2017)" by REE.

(2) Includes biogas, biomass, hydraulic marine, and geothermal.

TABLE 6.3.5 ENERGY BALANCE (GWh)

TECHNOLOGY	2017 (1)	2030
Hydraulic	20,721.6	20,721.6
Nuclear	**55,539.4**	**-**
Coal	**42,424.3**	**-**
Fuel/Gas	-	-
Combined Cycle	**33,648.0**	**78,629.5**
Wind	47,508.1	130,531.6
Photovoltaic	8,000.3	140,303.4
Solar thermal	5,348.0	10,900.8
Other renewables (2)	5,504.2	5,504.2
Cogeneration	27,947.0	-
Residues	3,410.2	-
Generation	**250,051.1**	**386,591.1**
Demand (3)	**256,083.9**	**285,152.6**
Generation - Demand	**-6,032.8**	**101,439.1**

Source: self-made

(1) Date taken from ESIOS.

(2) Includes biogas, biomass, hydraulic marine, and geothermal.

(3) Energy demand at generator terminals minus Pumping consumption.

TABLE 6.3.6 COST OF THE SYSTEM, REMUNERATION, CAPACITY PAYMENTS

	2017			2030		
	3 %	7 %	10 %	3 %	7 %	10 %
Costs of the System (billion $)	18.05	22.51	26.60	37.95	46.69	54.28
Remuneration of generators (billion $)				24.81		
Payment by capacity mechanisms (billion $)				13.14	21.88	29.47

Source: self-made

7. DISCUSSION

When energy demand is scaled to 2030, implying an annual increment of 0.9 %, installed capacities must also increase to assure that demand can be covered. Not only it increases due to an increase of demand, but also because of the nature of technologies installed to generate energy. As more renewable technologies are introduced, a larger capacity must be installed, since renewable technologies have a significantly lower capacity factor. A difference between installed capacities in 2030 when different base scenarios are considered is also observed: when 2014 is the base scenario, installed capacity grows a 77.96 %, while this growth is a 103.64 % when base scenario is 2017. This difference is explained by the climate nature of base scenarios: when a year is dry (2017), the energy generated with installed capacity of hydraulic technologies is less than that of a rainy year (2014), so more capacity of other technologies whose generations is not much dependent to climate variation must be installed.

A relevant issue is the overproduction of energy that occurs when it is decided to make renewable technologies produce 80 % of total energy generation while imposing a minimum of 5 GWh of thermal generation to assure the security of the system. This decision implies a spillage of almost 97,000 GWh a year.

7.1 Study case 1: nuclear, combined cycle and coal as conventional technologies

When these three technologies are considered for covering the thermal energy demand, one thing is clear: coal technologies are economically suboptimal to be part of the generation mix. Their considerably high investment and variable costs make them too expensive to invest on them and to operate them if other alternatives are present. This fact leads to a situation where nuclear and combined cycle technologies are the ones covering the thermal demand. In general, there is more combined cycle than nuclear capacity installed, since its investment costs are significantly lower (4 times lower), but as interest rate increases this difference in installed capacity is even larger. On the other hand, as variable costs of combined cycle technologies are higher (almost 4 times higher), they only operate when nuclear technologies are not able to cover all thermal demand by themselves. This fact brings up a problem: there are some hours when nuclear technologies are the only ones operating, meaning that they must match the demand by changing their level of energy production, and that is something nuclear generators are not prepared for, so that is another issue that should be solved if a generation park like the one presented in this scenario was taken to practice.

Average cost of electricity increases in 2030 scenario described with respect to the base scenarios due to the higher values that LCOEs of renewable technologies have compared to those of nuclear, coal and combined cycle technologies, with the exception of hydraulic energy, which has the lowest LCOE of all technologies considered in this study. For this reason, average costs of energy in 2030 with 2017 as base scenario are higher than those with 2014 as base scenario, since hydraulic energy production is much lower.

7.2 Study case 2: nuclear technologies out of the mix

Investment and variable costs of nuclear technologies are significantly different depending on the sources checked [14]. Some NGOs, as Greenpeace [20], state that apart from the potential environmental impact that this technology has, which is another subject of discussion, nuclear technology requires extremely high investment costs, which makes it economically suboptimal unless there are subsidies or political interests behind. Due to all the uncertainty that surrounds this technology, it is not unreal to expect a future without it.

The investment cost for nuclear technology considered in this project is 3,000 $/kW, which make it economically optimal to be part of the thermal generation mix but, as it has been said, data of nuclear technology investment costs can vary significantly depending on the source checked, so the investment costs that make it suboptimal have been found, taking into account three different interest rates. When interest rate is 10 %, these investment costs are 3,771 $/kW, which is a value that is in the range of investment costs review in the already mentioned article.

If nuclear technology was no longer on the generation mix, coal technology would get into it, although installed capacities and energy generations distribution between the two conventional technologies operating, when interest rate is low (3 %) would be different than in the situation when nuclear and combined cycle technologies were the ones operating. If nuclear and combined cycle technologies were the ones operating as conventional technologies, their installed capacity relation would be 3 to 2 in favor of combined cycle technology, but if coal technology substitutes nuclear, there would be 3 times more combined cycle capacity installed than coal. If interest rate is high (7% or 10 %), installed capacity of the technology that accompany combined cycle is the lowest possible one in any case.

When nuclear technology is no longer in the mix, average cost of electricity increases around 5 $/MWh when interest rate is 3 %, it is almost the same if interest rate is 7 %, and it decreases slightly when interest rate is considered to be 10 %. This is again related with the LCOEs: with low interest rates, LCOE of nuclear technology is lower than the one of coal technology, and vice versa with high interest rates.

7.3 Study case 3: combined cycle as the only conventional technology

If combined cycle were the only conventional technology operating in the generation mix, its variable costs would set the price of electricity in the market since it would be the last one entering the mix. Selecting 11 combined cycle units, an equivalent combined cycle unit that would represent all combined cycle units in the generation mix can be modelled. Its variable costs would provide the price of electricity in the market, which would oscillate between 64.50 $/MWh and 64.67 $/MWh. If electricity market rules do not change, generators do not receive anything else but the price of electricity they produce, which would not be enough to cover all costs of the system. For this reason, it is necessary to plan some mechanisms to pay generators the additional money they need to cover all their costs, known as payments by capacity mechanisms.

8. CONCLUSION

Designing an electricity system with a high penetration of renewable energies represents a complex task where many new challenges rise up.

One of the biggest issues faced is the impossibility of programming the energy production of renewable energies. If renewable energies represented 80 % of total energy production in a year, there would be many hours when an overproduction of energy would happen, supposing an energy spillage. However, this spillage could be reduced by utilizing energy storage technology, developing a wider interconnexion system with other countries, and performing a smart energy demand.

Because of the unprogrammable nature of renewable technologies, a predefined minimum of conventional technologies generation should be established to assure the well-functioning of the system, which would translate into an extra cost.

Renewable technologies, in general, have much lower capacity factors than conventional technologies, so much more capacity should be installed in order to generate the same amount of energy than a situation where the generation were distributed as it is nowadays.

If coal, nuclear and combined cycle technologies were the only conventional technologies available to cover the thermal demand, it is clear that nuclear and combined cycle technologies would be the most economically efficient ones to do so. But a big problem would arise when nuclear were the only one operating, since this technology is design to produce energy at a constant power level, with very low variable costs in that case, making it uncapable of responding to changes in demand. So, it seems unreal to operate an energy system in which nuclear technology were the only programmable technology.

If investment costs of nuclear technology were significantly higher than the ones considered in this study, then it would no longer be economically optimum to operate. This situation is considered because there is an opaque atmosphere around costs of nuclear technology, and its costs are significantly different depending on what resource is consulted. If interest rate were 10 %, an investment cost of just 25 % higher than the one considered in the study would convert nuclear technology in an economically suboptimal technology. In that case, coal technology would take its place in the generation mix, which would make average costs of electricity rise compared to a situation where nuclear technology were in it, because variable costs of coal technology are much higher.

Finally, if combined cycle technology were the only programmable technology operating, it would always be the last one entering the generation mix since it has the highest variable costs. These costs would be the ones setting the price of electricity every hour, so this technology would never cover their fixed costs with its remuneration perceived. It is observed that costs of the system double the remuneration perceived by all generators, which only perceive the price of electricity they generate. This situation leads to considerably high payments by capacity mechanisms that would be added in some way to the final electricity bill.

APENDIX A: ACRONYMS

CNMC	*Comisión Nacional de los Mercados y la Competencia*
EU	*European Union*
EDP	*Energias de Portugal*
E·SIOS	*Sistema de Información del Operador del Mercado*
GDP	*Gross Domestic Product*
LCOE	*Levelized Cost of Energy*
MINETUR	*Ministerio de Industria, Comercio y Turismo*
NGO	*Non-governmental Organization*
REE	*Red Eléctrica de España*
OECD	*Organization for Economic Cooperation and Development*
OMIE	*Operador del Mercado Ibérico de Energía*
PVPC	*Precio Voluntario al Pequeño Consumidor*
WHO	*World Health Organization*

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